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IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	Docket No. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	Docket No. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	Docket No. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	Docket No. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	Docket No. E-01933A-98-0471

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimony of Dr. Richard A. Rosen, in the above-referenced matter.

RESPECTFULLY SUBMITTED this 29th day of May, 2002.

Arizona Corporation Commission
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Scott S. Wakefield

Scott S. Wakefield
Chief Counsel

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By Rinda Reeves
Linda Reeves

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES	))))	DOCKET NO. E-00000A-02-0051

DIRECT TESTIMONY

OF

DR. RICHARD A. ROSEN

On Behalf of the Arizona
Residential Utility Consumer Office

Tellus Institute
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May 29, 2002

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SECTION I - SUMMARY OF TESTIMONY

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Dr. Richard A. Rosen. My business address is Tellus Institute, 11 Arlington Street, Boston, MA 02116-3411.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. Appendix 1, which is attached to this testimony, describes my educational and professional background.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. In this case, I am providing expert testimony on behalf of the Residential Utility Consumer Office ("RUCO").

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS THUSFAR IN THIS CASE.

A. Certainly. My major conclusions and recommendations are as follows:

1. The regulatory issues affecting electric industry restructuring are far more complex than most analysts and commissioners believed just a few years ago, when the ACC established electric restructuring regulations for Arizona.
2. There are many analytical, legal, and regulatory studies that should be done for Arizona before electric industry restructuring or generation divestiture should proceed.

3. The main lesson of the California and related state restructuring experiences is that the ACC should proceed slowly and cautiously if it decides to continue to pursue electric industry restructuring.
4. Therefore, the ACC should re-examine all the pros and cons of restructuring before proceeding with either generation divestiture or a competitive bidding process for generation.
5. The divestiture of APS' and TEP's existing generation units to unregulated affiliates should only be done if long-term purchased power agreements (PPAs) are established such that utility ratepayers continue to have access to all the power from these units at traditional cost-of-service retail rates. Otherwise, ratepayers will lose the substantial economic value of these units. If PPAs are not established, divestiture should not proceed, and electric restructuring in Arizona should be abandoned.
6. In contrast, if the ACC decides to keep the divestiture of existing generating units open as an option without a firm commitment to cost-of-service PPAs, the current target date for accomplishing divestiture of January 1, 2003 should be postponed until at least January 1, 2004 in order to give the ACC adequate time to consider all the relevant restructuring issues.
7. The potential exercise of generation-related and transmission-related market power in Arizona, given its significant load pockets, is a serious threat to the potential success of deregulation.

8. The Standard Market Design that FERC staff has proposed for all RTOs is highly problematic, and the ACC should not allow Arizona utilities to participate in an RTO until the net benefits of such an institution to Arizona are clearly demonstrated.
9. Thusfar, FERC has failed to demonstrate net economic benefits from RTOs.
10. Any competitive bidding process for generation that is used in Arizona should be based on least-cost planning principles, and should integrate planning for demand-side management technologies as well as new transmission system investments, with bidding for generation.
11. If the divestiture of existing electric generation occurs both without long-term purchased power agreements being signed for the output of the units, and prior to an RTO being established, then the ACC will need to establish an agency, with FERC approval, to monitor and mitigate market power in wholesale power markets in Arizona.
12. The ACC should, in any event, set a required planning reserve margin for each utility distribution company that it regulates within Arizona, in order to ensure the continuation of adequate electric system reliability.

SECTION II – THE THEORY OF MARKET POWER IN ELECTRICITY MARKETS

a. Generation

Q. WOULD YOU PLEASE DESCRIBE WHAT YOU MEAN BY MARKET POWER IN THE CONTEXT OF DEREGULATED ELECTICITY MARKETS?

A. Yes. By "market power" I mean the collective impact of all the participants in any given electricity market such that the resultant price in that market is significantly above a competitive level (at least 5 percent above) for a significant period of time (such as one year or more, on average). In applying this definition, one must avoid the common mistake of attributing market power only to a single market participant, as in the sentence "Company A has market power." A single market participant in an extreme case might be able to exercise market power even if all other participants offer competitive prices for their output. The more common situation is that all market participants interact in complex ways such that, if market power exists, all participants have contributed towards the problem to some degree. The ability of market participants to collectively exercise market power should be thought of as a *systemic* result of their *collective behavior*.

Q. HOW DOES THIS DEFINITION OF MARKET POWER APPLY TO THE ABILITY OF GENERATION OWNERS TO EXERCISE MARKET POWER?

A. The ability of generation owners to exercise market power depends on all aspects of the structure of the power market in which they are operating. It also depends on the various transmission constraints that they face in a region, but I will ignore market power issues related to transmission for now, and discuss them below. The key structural features of a pure generation market that affect the ability of generation owners to exercise market power are:

a. The number and size of each generating unit.

b. The ownership of each generating unit.

c. The variable operating costs of each generating unit.

d. The shape of the load curve for demand in the region.

In addition, secondary factors determine the likelihood that generation owners can exercise market power in a region, such as whether the market is a short-term spot market, like the real-time day ahead market in California, or a purely a bilateral contract market. This is important because participants have exercised market power most effectively in a short-term spot market with a single market-clearing price of the type that FERC has established in California and the Northeast. However, prices in a region's spot market will very likely strongly influence prices in the region's bilateral contract market.

Q. WHAT ARE SOME OF THE KEY FEATURES OF ELECTRIC GENERATION MARKETS THAT ALLOW FOR THE EXERCISE OF MARKET POWER MORE EASILY THAN FOR OTHER INDUSTRIES?

A. Some of the features of electric generation markets that allow market power to be more easily exercised in this industry, when compared to other industries, are (1) the inability to store significant amounts of electricity in most parts of the country; (2) the almost complete price inelasticity of demand in the short run (demand declines very slowly with higher prices); (3) the steep slope of the cost-of-supply or dispatch curve for generating units (particularly during hours of peak demand)[1]; and (4) the large variation in the level of demand within the course of a single day.

Typically, electric system demand changes by about a factor of two between the off-peak hours in the middle of the night, and the peak periods during the day. Because of the lack of storage for electricity, demand and supply must balance precisely at each moment, and during peak demand periods, the variable cost of production (the dispatch costs for the next generating unit in the dispatch order) is often five to ten times higher than the marginal dispatch cost in the off-peak hours. The "marginal" dispatch cost is the variable cost of the most expensive plant dispatched. This set of factors that are unique to the electricity industry allow for market power to be fairly readily exercised for any given level of the concentration of plant ownership in comparison to other industries with similar concentrations of ownership.

Q. PLEASE EXPLAIN THE BASIC MECHANISMS BY WHICH MARKET POWER IS EXERCISED.

A. The two basic mechanisms by which market power is exercised in pure generation markets are strategic bidding and capacity withholding. Strategic bidding occurs when a generation owner can bid one of its generating units higher than the competitive price level, thereby increasing the market-clearing price paid to all generation owners in a given hour, including the price paid to the owner for all its

[1] The "cost-of-supply" curve is a graph of the amount of megawatts of generation available at any given variable cost. The variable cost of supply is the cents per kWh to operate the generating unit, and is primarily fuel costs.

power plants. This is particularly easy to understand in the context of a standard hourly spot market where the market operator (the ISO or RTO) accepts bids from all generators from lowest price to highest price in each hour, until total demand is satisfied. In such a market, a generation owner might accept the risk that a higher priced bid for a single generator may not be accepted since the additional revenues that the owner can obtain are "leveraged" if the bid is accepted and sets a higher market-clearing price for all the owner's units. All owners of electric generation will profit significantly by finding what is called the "Nash equilibrium" for bid prices. The Nash equilibrium is a theoretical point at which all generation owners maximize their individual and collective profits by bidding (and having their bids accepted) at supra-competitive price levels. In the real world, such a point can be approximated by bidders.

Q. HAS STRATEGIC BIDDING BEEN IN EVIDENCE IN US ELECTRIC GENERATION MARKETS IN THE PAST?

A. Yes, strategic bidding has clearly been a factor in US generation spot markets and bilateral contract markets. This has been particularly true in spot markets on days of high demand, when generation is in relatively short supply. However, strategic bidding can also be exercised to a somewhat lesser, but still significant, extent when demand is not near peak levels. The extent to which this can occur depends, again, on the steepness of the cost-of-supply curve, i.e., the dispatch cost curve. Strategic bidding was certainly exercised in the California and Western markets during the period from the summer of 2000 to the summer of 2001. However, strategic bidding has also led to the successful exercise of market power in the formal spot and bilateral contract markets of the Northeastern ISOs since they have become deregulated.

Q. WHAT ARE THE SUB-MARKETS THAT FALL UNDER THE GENERAL CATEGORY OF GENERATION MARKETS?

A. Typically, electric generation markets have three major components: energy markets, capacity markets, and ancillary service markets. My description of strategic bidding pertains most directly to spot energy markets. FERC is currently advocating that all RTOs establish energy "balancing" markets, a type of energy spot market, in each region of the US, including Arizona.

The capacity markets in the Northeast are generally *installed* capacity markets. The idea of an installed capacity market is that anywhere from once a month to once per year, UDCs could purchase installed capacity resources if they were short of capacity with respect to their required reserve margins. The three Northeastern ISOs have established required reserve margins to go along with installed capacity markets, and these have been approved by FERC.

Finally, ancillary service markets include such services as 10 and 30 minute spinning reserves, or operating reserves. These types of services are closely related to both energy and capacity markets, and thus the interactions between all of these kinds of markets can be quite complex. In general, complex market interactions, in my view, tend to facilitate the exercise of market power. FERC also advocates that all RTOs establish ancillary service markets.

Q. PLEASE EXPLAIN HOW CAPACITY WITHHOLDING CAN BE USED TO EXERCISE MARKET POWER IN ENERGY MARKETS, AS YOU NOTED ABOVE.

A. Capacity withholding means that bidders into a market do not bid energy from all of the capacity that they own. Bidders can force a system operator to dispatch a generating unit higher up on the bid curve if the bidder withholds some capacity from the energy market in a given hour that might normally be dispatched in that hour, because its variable operating costs are lower than the market-clearing price. They might justify "withholding" through false claims that their capacity has broken down and is being maintained, or some similar justification. The effect is to raise the market-clearing price above what it would have been if the withheld capacity had not been withheld.

Such capacity withholding and the resulting increases in market prices was very clearly witnessed in the California market last winter, and it was a factor, at least for a while, in the Northeast energy markets. In its June 19, 2001 California and Western market order, FERC outlawed capacity withholding.

Capacity withholding has a powerful compounding effect when exercised in combination with strategic bidding. To illustrate, if capacity withholding and strategic bidding, taken separately, might be able to raise the price by 10 percent, then simultaneously they might raise prices under the same circumstances by 40 percent, and not by 20 percent as one might naively think.

Q. YOU HAVE STATED THAT STRATEGIC BIDDING CAN OFTEN LEAD TO THE HIGHEST MARKET PRICES RELATIVE TO UNDERLYING COMPETITIVE LEVELS WHEN DEMAND IS CLOSE TO PEAK LEVELS. DOES THIS IMPLY THAT ENERGY MARKET PRICES AT TIMES OF RELATIVE SUPPLY SCARCITY COULD HAVE A LEGITIMATE "SCARCITY VALUE"?

A. No. In order to understand the concept of "scarcity value," it is first necessary to understand what a competitive energy and capacity market price would be. In order to simplify this discussion, I will just assume a simple spot market for energy, which is complemented by an annual installed capacity market. A competitive price in the energy market would only reflect the marginal cost of supplying the next unit of generation, and, therefore, the price would be the variable operating cost of the last unit dispatched.

Q. MANY ANALYSTS HAVE ARGUED THAT COMPETITIVE MARKET PRICES CANNOT MERELY EQUAL VARIABLE OPERATING COSTS, BECAUSE THEN MARKET ENTRY FOR NEW CAPACITY WOULD NOT OCCUR. IS THIS CORRECT?

A. Yes, it is true that in a competitive electricity market, the total market price cannot just equal the marginal cost of energy in that market. Somehow the market participants must be able to collect their fixed costs for new investments in generating plants, if new market entry is going to occur. However, this should be the function of the installed capacity market, not the energy market. As implied by its name, "installed capacity" market, the market-clearing price should approximately equal the annual fixed costs of new capacity, e.g., a new peaker, net of any fixed costs that it can recover in the energy market. Thus, in a properly functioning competitive electricity market, the variable production costs of generating units, including those of the last peaker dispatched, should be recovered in the energy market. The remaining fixed costs of production should be recovered in the capacity market. If these two markets work properly in tandem, then price spikes in the energy market should not occur.

Many analysts have stated that price spikes in the electricity energy market are justified during times of peak demand in order to allow recovery of fixed investment costs. Based on the model for a competitive electricity market described above, this would only be true if there were no installed capacity market. One of the biggest deficiencies in the market structure that FERC approved for California was FERC's failure to require an installed capacity market and reserve margin, even though FERC required both in the three Northeastern ISO electricity markets. These requirements prevented the Northeast from having as significant a market power problem as California had in 2000.

If a competitive energy and capacity market are working properly in tandem, the highest price in the energy market during peak demand should be the variable cost of the most expensive peaker dispatched. That price would almost certainly be below $100 per mWh. The very high price spikes above this level, as occurred in the California and Western markets, would have been avoided if FERC had insisted on collecting fixed generation costs through an installed capacity market. This model of a competitive electricity market is described in greater detail in Exhibit ___(RAR-2) attached, which is a FERC filing in Docket No. EL01-118-000 that I drafted on behalf of the New Mexico and Rhode Island Attorneys General. This filing provides a more detailed discussion of many of the issues discussed above.

Q. HOW HAS THE POTENTIAL EXERCISE OF MARKET POWER BEEN MEASURED IN THE PAST, AND ARE THESE METHODS RELIABLE?

A. In the past, the potential for the exercise of market power in electricity markets has been measured primarily by focusing almost entirely on the market concentration or ownership levels of the generation owners. One index of potential market abuse that FERC has especially relied on is the Herfindahl-Hirschmann Index, or HHI. The HHI is simply the sum of the squares of the market concentration of each generation owner (measured in percentages). Thus, a completely concentrated market with one owner owning 100 percent of all plants would have an HHI of 10,000. If there were two equal sized owners the HHI would equal 5,000, and for five equal sized owners the HHI would be 2,000. FERC, the US Department of Justice, and the Federal Trade Commission would generally become quite concerned if the HHI exceeded 2,000 for any given market.

The important point is that this traditional scheme for measuring the potential for the exercise of market power is totally arbitrary for electricity markets. The HHI does not reflect the details of any particular market structure or industry, nor does it reflect the key characteristics described above such as the shape of the demand curve, the shape of the supply curve, or the distribution of each generation owners' units throughout the supply curve, which is critical for any given owner to successfully increase the market-clearing price.

Q. IF THE HHI IS NOT SUFFICIENTLY SOPHISTICATED TO MEASURE THE POTENTIAL FOR MARKET POWER IN A GIVEN MARKET, WHAT APPROACH IS APPROPRIATE FOR THIS PURPOSE?

A. Because the HHI and all previous attempts at measuring the potential for the exercise of market power are inadequate to the task because they are much too simplistic, the only possible approach is *simulation modeling* of the collective gaming behaviors of generation owners that, in fact, cause market power. This is what Prof. John Nash showed in his Nobel Prize winning research, which led to his determination of a Nash equilibrium in various types of behavioral situations such as bidding in electricity markets. Because market power is the result of the collective behavior of bidders into a particular type of market structure, the type of market structure, and the type of generation resources with which to bid, will have a key influence on the outcome.

In sum, the rules of the game matter, and the resources one has with which to play any particular game matter. The theoretical potential for market power can be assessed only through simulation modeling of this game-playing behavior. Of course, the actual level of market power in real world markets could be less than or greater than implied by game theory.

Q. YOU HAVE STRESSED HOW MARKET POWER CAN BE EXERCISED IN ENERGY MARKETS FOR ELECTRICITY. CAN MARKET POWER ALSO BE EXERCISED IN CAPACITY MARKETS FOR ELECTRICITY?

A. Strategic bidding and capacity withholding can lead to market power in any type of electricity market. In fact, the PJM Market-Monitoring Unit claims to have found instances of market power in its installed capacity market. Similarly, officials had claimed to find market power in California's ancillary services markets, even before the blow-up of prices in the California energy market. However, to my knowledge, the mathematics of how market power might be exercised in the energy market is better understood than the mathematics of how market power might be exercised in the capacity or ancillary service markets.

Q. WHY IS IT NECESSARY TO INCLUDE A REQUIRED RESERVE MARGIN AS PART OF AN INSTALLED CAPACITY MARKET?

A. A required reserve margin is a necessary part of an installed capacity market for the same reasons that it is necessary for resource planning under regulation. A required reserve margin ensures that system reliability will be maintained at a sufficiently high level. If a required reserve margin were not part of an installed capacity market UDCs would have no incentive to purchase installed capacity at all. The UDCs could just contract for energy to cover their load in the spot energy market, and the price for installed capacity would fall below the cost of new market entry. Eventually, UDCs would have no reserve capacity, and reserve margins would fall to unacceptably low levels, as they did in California by 2001. This situation would present a grave danger to system reliability. Thus, even in deregulated generation markets one must impose a required reserve margin on all UDCs in order to preserve system reliability.

Q. EARLIER YOU STATED THAT ELECTRIC ENERGY MARKETS SHOULD ALLOW GENERATORS TO RECOVER THEIR VARIABLE COSTS OF PRODUCTION, AND THAT CAPACITY MARKETS SHOULD ALLOW GENERATORS TO RECOVER THEIR NET FIXED COSTS. WOULD YOU PLEASE REVIEW WHAT YOU MEAN BY "NET" FIXED COSTS?

A. Yes. In a formal energy spot market or energy balancing market of the type that FERC has proposed for all RTOs, even if all generators bid only their variable costs of production into the energy market, all generators that are dispatched, except the single one that sets the market-clearing price, will recover more than their variable costs. This is because all are paid the same market-clearing price. For example, if the market-clearing price is set by unit B at 3.0 cents per kwh, then unit A, whose variable costs were only 2.0 cents per kWh, would get to keep the additional 1.0 cent per kwh from the market-clearing price. Thus, this 1.0 cent per kWh is implicitly a contribution toward covering its fixed costs. Presumably, the rest of unit A's annual fixed costs, including a reasonable rate of return on equity, would be recovered from the installed capacity market, if there were one.

b. <u>Transmission</u>

Q. HOW DOES THE TRANSMISSION SYSTEM AFFECT THE ABILITY OF GENERATION OWNERS TO EXERCISE MARKET POWER?

A. The transmission system affects the ability of generation owners to exercise market power in two primary ways. The first is an economic consequence of pancaked transmission tariffs. "Pancaked" transmission tariffs refer to the current situation where generators must pay more than one transmission charge to wheel power from outside the control area of an Arizona UDC, into that control area, whereas only one transmission charge applies within the UDC's own transmission system. Thus, because of the outside generators' higher transmission costs, generators outside a UDC's control area usually are at a competitive disadvantage relative to generators within that control area to compete to serve load in that control area. FERC wants to establish very large RTOs in order to reduce or eliminate the pancaking of transmission rates over large areas of the US so that wholesale electricity markets become more competitive.

Q. WHAT IS THE SECOND WAY IN WHICH TRANSMISSION SYSTEMS FACILITATE THE EXERCISE OF MARKET POWER?

A. Transmission systems also facilitate the exercise of market power when *physical constraints* limit the extent to which power can flow between potential sources of power, and potential markets for that power. Such physical constraints are very common in the US, but are particularly important in the Western portion of the US. This is because many large western cities with high electric demand are located at fairly large distances from each other. Under traditional regulated conditions, when most utilities were vertically integrated, these load centers received power from relatively nearby power plants. However, a deregulated generation market presents many challenges in this context, because the transmission system limits the physical ability of distant sources of competitive power to compete for most western load centers. Thus, most western cities like Phoenix are called "load pockets," large loads within transmission-constrained regions.

Q. DOES THE EXISTENCE OF LOAD POCKETS IMPLY THAT THE EXISTING TRANSMISSION SYSTEM HAS BEEN POORLY PLANNED, OR THAT IT NEEDS UPGRADING?

A. No. Even if vertically integrated utilities properly used least-cost planning for their systems, it might still be least cost for some transmission constraints to exist, especially around small regions with large loads, like cities. This reflects the economic trade-offs between building new transmission lines into a city from a distant generating unit, and simply building a new generating unit inside the load pocket. This second option is often cheaper. The transmission systems of vertically integrated utilities were not designed, nor should they have been designed, simply to maximize the ability of outside generation sources to compete to serve load within the load pocket.

One consequence of this analysis is that society may need to incur *additional costs* merely to facilitate competition for generation sources within load pockets. This represents an economic inefficiency of establishing a competitive market framework, relative to least cost planning under traditional cost-of-service regulation.

Q. ARE THERE ANY OTHER WAYS IN WHICH THE TRANSMISSION SYSTEM MIGHT FACILITATE THE EXERCISE OF MARKET POWER?

A. Yes. As part of establishing RTOs, FERC has advocated that congestion cost pricing mechanisms also be established for transmission services. The approach that FERC advocates would cause generation market prices to be the basis for pricing transmission services across transmission-constrained interfaces. This is because congestion-based prices would be derived from the differences in market-clearing prices in spot energy markets between the two sides of the congested interface. Thus, the terminology "congestion costs" is a misnomer, because "congestion-cost" pricing would reflect market *prices*, not the actual *costs* of congestion. This means that if market power exists in the generation markets where transmission congestion occurs, which is likely, then the prices for transmission services would also be inflated due to market power, in addition to the prices for generation being inflated.

Q. IS THERE A DANGER THAT CONGESTION-COST PRICING SCHEMES COULD LEAD TO DUPLICATE CHARGES TO RATEPAYERS FOR TRANSMISSION SERVICES?

A. Yes, there is a danger that congestion-cost pricing schemes could lead to duplicate or excessive charges to customers for transmission services. One way in which this could happen is if the competitive market-clearing price within a load pocket is much higher than the cost of generation that a UDC has contracted for within the load pocket. This would represent an excessive or duplicative charge if the UDC is charged for transmission services into the load pocket based on the higher market-clearing price due to the use of congestion-cost pricing for those transmission services, since the UDC in question had already covered its peak demand needs with the lower-cost generation contracts. A generating unit that was dispatched to serve some other UDC's needs might have set the higher market-clearing price, and yet all transmission services across the same interface would be priced on the same basis. One lesson here is that any very complex market-based scheme like congestion cost pricing should only be attempted after the generation markets have become competitive. Even then, if this can be achieved, one must be careful to avoid unintended consequences of non-competitive generation markets.

Q. IS FERC ADVOCATING THE ESTABLISHMENT OF ANY OTHER MARKET MECHANISMS THAT MIGHT IMPACT THE PRICES OF TRANSMISSION SERVICES?

A. Yes, FERC is advocating the establishment of additional market mechanisms in order to determine the price of transmission services. In particular, FERC is advocating that direct markets for firm transmission rights (FTRs), or similar markets, be established. One idea FERC has is that the purchase of an FTR to transmit power on a firm basis between two points would allow the owner of this FTR to avoid the payment of congestion costs between those two points. Once an initial allocation of transmission capacity to generation owners or UDCs is accomplished, then a secondary market would exist for buying and selling FTRs. FERC has not addressed the likelihood that market power could be exercised in FTR markets as well as in generation markets. To my knowledge, FERC has not yet established any procedures for analyzing such markets to determine whether market power is being exercised or not. FERC has no monitoring or mitigation procedures in place for such markets.

Q. TAKING A STEP BACKWARDS, DO YOU UNDERSTAND WHY FERC IS TRYING TO UTILIZE MARKET MECHANISMS TO PRICE TRANSMISSION, GIVEN THE VERY DIFFICULT PROBLEMS WITH DOING SO THAT YOU HAVE CITED?

A. No, I do not understand why FERC is so determined to establish market mechanisms as a basis for pricing transmission services. There are two main reasons why I believe this is probably not a wise direction in which to go from a national electricity policy perspective. (I suggest reading the two recent policy papers put out by FERC staff on the standard market design and ratemaking/pricing options in March and April 2002 as part of Docket No. RM01-12-000 to understand more of the context of this discussion.) I do not believe that the existing system of network service and point-to-point transmission tariffs for wholesale generation resulting from FERC Order No. 888 is really "broken." Therefore, it does not need fixing. (See the comments in Exhibit___(RAR-1) for more details on this point.) Those tariffs provide a fairly equitable and very simple way of charging wholesale customers for transmission services.

Secondly, since transmission costs are generally less than 10 percent of the total cost of electricity, and given the many problems some of which I have described above with using market mechanisms to price transmission, I believe that FERC should first focus its attention on trying to get wholesale generation markets to be workably competitive, since they contribute about 60 percent of the total cost of electricity. If that goal is ever reached, then FERC can experiment with the use of market mechanisms for pricing transmission.

Q. ARE THERE ANY OTHER SERIOUS PROBLEMS WITH FERC's RECENT EFFORTS TO ESTABLISH A STANDARD MARKET DESIGN FOR TRANSMISSION PRICING?

A. Yes, there is another serious problem with FERC's recent efforts to establish a standard market design for transmission pricing, which is that FERC wants this scheme to apply to *all* transmission, not just wholesale transmission. FERC staff explicitly states in the position papers cited above that the standard market design would apply to *retail* transmission prices also. This is, of course, a very dramatic development, and one that FERC may not, in fact, have legal authority to mandate under the Federal Power Act. (Again, please see Exhibit ___(RAR-1) for a discussion of some of these legal issues.) FERC's proposal for the use of market mechanisms to price transmission services potentially impact the bundled or unbundled transmission rates that most retail ratepayers in the US would pay. Thus, FERC's recent proposal would subtract from the authority of the Arizona Corporation Commission (and all other state PUCs) to set retail electricity rates for Arizona consumers.

Q. HOW DOES FERC's PROPOSAL FOR A STANDARD MARKET DESIGN RELATE TO THE ISSUE OF ESTABLISHING REGIONAL TRANSMISSION ORGANIZATIONS (RTOs)?

A. FERC's proposal for a standard market design (SMD) is the basis for much of the market structure that an RTO would implement. It is a major part of the functions that all RTOs, including WestConnect, would need carry out in order to win FERC's approval.

Q. WHY DO YOU RAISE THESE RTO-RELATED ISSUES AS PART OF YOUR TESTIMONY IN THIS GENERIC RESTRUCTURING DOCKET IN ARIZONA?

A. I am raising these SMD issues that FERC wants to see as part of all RTOs in this docket because I believe that the ACC must take FERC's policy directions into account as it decides what additional market structures to put into place in Arizona, if any. For example, if the ACC became convinced that FERC's conception of an RTO was a bad idea for Arizona, the ACC might want to do everything in its power to prevent the formation of an RTO for Arizona, including keeping retail electric rates bundled under traditional rate regulation. The ACC might want to do this because FERC's legal authority may depend on whether or not the ACC continues in the policy direction of unbundling and restructuring the electric industry, or whether it decides to return to traditional, bundled cost-of-service regulation.

Q. HAS FERC PERFORMED ANY ANALYSES AS TO WHETHER THE ESTABLISHMENT OF RTOs WOULD BENEFIT ALL PARTS OF THE US, INCLUDING ARIZONA?

A. Yes, FERC released a study by the consulting firm ICF, Inc. on the costs and benefits of RTO formation throughout the US on February 26, 2002. As usual, FERC requested comments on that study from interested parties in Docket RM01-12-000. I have drafted comments for the states of New Mexico, Colorado, Rhode Island, and Maine in response to that request. These comments provide a detailed, and, in my view, devastating critique of the ICF study. Many other parties, especially other state PUCs, submitted highly critical comments on this study as well. I believe that it is fair to say that the consensus of most comments was that this was a very poor analysis that does not demonstrate that RTOs would provide any economic benefits to most of the US. It is my opinion that FERC should start over and perform a proper economic analysis of RTO formation. FERC has never demonstrated that a region like Arizona will benefit on a net economic basis from the establishment of an RTO.

To me, this implies that the ACC should be very skeptical about accepting FERC's assumption that RTO formation, in general, would provide net benefits to all states, particularly those in the West. The ACC should also be skeptical that having a standard market design of the type their staff has proposed is a good idea for all states.

Q. BASED ON FERC's RESPONSE TO THE VERY HIGH PRICES EXPERIENCED IN THE CALIFORNIA AND WESTERN WHOLESALE ELECTRIC MARKETS LAST YEAR, DO YOU BELIEVE THAT FERC SUFFICIENTLY UNDERSTANDS HOW MARKET POWER CAN BE EXERCISED TO BE ABLE TO CONTROL IT IN THE FUTURE?

A. No, I believe that FERC's response to the very high prices in the Western wholesale markets last year was very weak and very late. I will discuss some of the more detailed aspects of how they monitored and mitigated prices in both that market, and in similar ISO markets in the Northeast, below. But, even more importantly, I believe FERC's response to the exercise of market power in the West last year was so inadequate because FERC did not and does not properly and completely understand the mechanisms for exercising market power. I believe FERC understands how capacity withholding can lead to market prices that are not just and reasonable under the Federal Power Act, but I do not think that FERC fully understands how strategic bidding works under all types of market conditions, especially during non-peak demand hours. I have described some of my concerns regarding this issue more fully in Exhibit___(RAR-2).

Q. IF FERC DOES NOT FULLY UNDERSTAND STRATEGIC BIDDING, WHAT IMPLICATIONS WOULD THIS HAVE FOR THIS ELECTRIC RESTRUCTURING DOCKET IN ARIZONA?

A. If FERC does not fully understand strategic bidding, the ACC should be extremely cautious before continuing along their earlier determined route towards restructuring the electric industry in Arizona. One reason for this is that by proceeding to restructure the electric industry, the ACC will be placing much more responsibility on FERC, than on itself, to ensure that the exercise of market power does not unnecessarily raise retail rates for Arizona customers. Yet, if FERC does not understand market power properly, how could giving FERC that responsibility be justified? By entrusting FERC to carry out the vital functions of monitoring and mitigating the Arizona wholesale electric markets for market power, the ACC could be risking far too much in return for, as of yet, unspecified benefits. Thus, I believe the ACC should proceed with electric restructuring, including generation divestiture, only if it is clearly convinced that FERC can do an adequate job of preventing market power from infecting retail electric rates in Arizona, given the substantial complexities involved in creating deregulated markets for both generation and transmission in the first place.

SECTION III – MARKET POWER MONITORING AND MITIGATION

Q. WHAT WERE SOME OF THE PROBLEMS WITH THE WAYS IN WHICH FERC MONITORED AND MITIGATED MARKET POWER IN THE CALIFORNIA AND WESTERN MARKETS LAST YEAR?

A. The first problem is, as far as I could determine at the time, that FERC did not initially want to do anything about the exercise of market power that was clearly happening in the Western power markets. When pushed to do something, at first FERC only set very high price caps on the market prices, which are almost useless for mitigating market power. These price caps were the same in all hours. For example, a price cap of $250 per mWh is about 8-10 times the typical energy market price in the West, so such a cap would not provide much protection to consumers in most hours of the year. At best, it would only serve to mitigate the most serious price spikes during peak hours, but even then market power could still be exercised. As I have discussed in the previous section, if FERC had just established an installed capacity market in the region, there would have been no justification for price spikes to occur at all.

Finally, in June 2001, FERC established much lower price caps in the energy market based on the marginal costs of production from the most expensive peaking units. These price caps were in the range of $100 per mWh, or 10 cents per kWh. While this and other measures did help cool the markets down, such an approach to setting price caps still would not, in general, provide much protection to customers from market power. The reason for this is that while a price cap of about $100 per mWh might be appropriate during the peak periods when the least efficient peaking units run, it is of no use during most hours of the year, when much lower cost generating units set the market-clearing price.

For example, if in many hours units with an operating cost of $40 per mWh set the market-clearing price, then if the exercise of market power led to a 25 percent increase to $50 per mWh, a $100 per mWh price cap would deem this price to be perfectly allowable. Therefore, by setting a price cap either very high, or a cap that is constant in all hours, FERC provides the consumer with little or no price protection.

The current Western price caps also only apply to the spot market prices for energy only. They do not apply to the more common method of purchasing power, namely through the bilateral contract market. This is another serious problem with FERC's approach to monitoring and mitigating market power. FERC has outright refused to monitor and mitigate market power in the bilateral contract market. FERC justifies this approach by claiming that if they do an effective job at limiting market power in the spot energy markets, the bilateral contract market prices will also moderate down to the levels in the spot market, since the spot market can always be used as a fall back if the bilateral contract markets become over-priced. However, this is a weak argument, because it overlooks the complexities of and differences in these markets.

Finally, another problem with the way in which FERC monitored the Western wholesale markets last year was that they declared capacity withholding to be illegal, but they did not establish an institutional mechanism for enforcing this edict outside of California. Thus, as far as I can see, outside of California, this anti-capacity withholding rule was, and still is, unenforceable.

Q. IS THERE EVIDENCE IN THE WESTERN POWER MARKETS FROM 2000-2001 THAT MARKET POWER IN THE SPOT MARKETS CONTRIBUTED TO MARKET POWER IN THE BILATERAL CONTRACT MARKETS?

A. Yes. Many utilities in the West, including utilities in California, Washington, and Nevada, all have claimed that market power in the spot market in California caused the prices of many bilateral contracts that they signed during 2000-2001 to be unjust and unreasonable under the Federal Power Act. Specifically, there are several cases currently pending at FERC to resolve this issue.

Q. HOW WILL THE NEW LEGISLATION RECENTLY PASSED IN CALIFORNIA THAT WAS REFERRED TO IN CHAIRMAN MUNDELL'S LETTER OF MAY 14, 2002 LIKELY INFLUENCE THE WESTERN POWER MARKETS?

A. California Senate Bill No. 39 appears to be designed, in part, to assure that electric generating units are available when needed to meet system demand. The underlying motive behind this legislation appears to be to attempt to eliminate capacity withholding for the purpose of endangering system reliability, and more indirectly, for the purpose of increasing market prices. This legislation appears to be quite thorough, and is likely to be effective at accomplishing its goals.

Assembly Bill No. 28 is somewhat broader and less specific. It gives the California Oversight Board the power to investigate almost any matter involving the wholesale market in California. Of course, it is not clear legally what the Oversight Board could do to take corrective action if they found a problem, except to file a complaint at FERC. This legal issue, and the practical consequences of it, will require more research and analysis than I have been able to do thus far.

Q. IF FERC HAS NOT DONE WELL IN MONITORING FOR AND MITIGATING MARKET POWER IN THE WEST, HAS IT PERFORMED BETTER IN THIS REGARD IN THE THREE FORMAL ISO MARKETS IN THE NORTHEAST?

A. No, FERC has not done much if any better at monitoring and mitigating market power in the formal ISO energy markets in the Northeast. The three ISOs in the Northeast are: PJM, New York and New England. I have studied the market monitoring rules for the New York and New England ISOs in considerable detail over the past two years, and I have personally met with the New England ISO Director of Market Monitoring.

With respect to monitoring for market power, the real weakness there is that FERC has not required the ISOs to collect the underlying operating cost data for each of the generating units, although FERC has authorized the ISOs to collect this data if they believe it is necessary to do so. Unfortunately, the ISOs have not done this, so they do not know what the true operating costs of the generating units are. Yet, if they do not know what the underlying operating costs are, then they cannot tell whether or not market power is being exercised in the energy markets that they monitor.

In addition, even when the Northeastern power markets have experienced some fairly significant price spikes, particularly on hot summer days when demand is near peak, to my knowledge the ISOs have never ordered refunds, and only occasionally do they reset market-clearing prices after they have been set such that they reflect the exercise of market power. Thus, the most extreme instances of the exercise of market power have generally passed with no mitigative action having been taken. FERC has also argued that it can only order refunds within 60 days after a complaint is filed. However, FERC is tentatively exploring establishing a rule that will allow for refunds on an ongoing basis, if market power occurs.

Q. IF THE NORTHEASTERN ISOs DO NOT KNOW WHAT THE UNDERLYING COSTS OF PRODUCTION ARE FOR GENERATING UNITS, HOW DO THEY MONITOR THE ENERGY MARKET FOR THE EXERCISE OF MARKET POWER?

A. Basically, the three ISOs utilize what I call "self-referential" rules for trying to detect market power. By "self-referential" I mean the rule compares each generator's ongoing or contemporary market bids to bids made from the same generating units in the past. If a current bid is too far above the average of past bids for the same generating unit, then the current bids might be mitigated downward by the ISO. The extent to which this change or mitigated bid lowers the market-clearing price on an ongoing basis is how the ISOs claim to mitigate the potential exercise of market power.

The problem with this self-referential approach, where current bids are compared to prior bids from the same generating unit, is that it cannot begin to control market power except in the most extreme cases. For example, a typical self-referential monitoring rule might say that if a current bid is more than 200 percent higher than the past three-month average of bids from that same generating unit, then an investigation will occur, and the bid could be mitigated. One problem is, of course, that a 200 percent increase over a period of only three months is such a large increase, that this rule provides little control over a generation owner's ability to raise prices in order to exercise market power. This type of rule can only control extreme events such as when a generation owner is tempted to increase its bid by ten times the old average in one month in order to profit from a heat wave. Of course, the generation owner can always get around such a potential restriction by always bidding one of its small and inefficient units at a very high price consistently, so that the monitoring rule will never provide a constraint when such a high price may actually be accepted by the ISO for dispatching and for setting the market-clearing price. Thus, most of the market power monitoring rules that are in place in the Northeastern energy spot markets are toothless, and, therefore, useless for the purpose of detecting market power.

Q. DOES FERC HAVE ANY MONITORING RULES IN PLACE FOR THE CONGESTION-COST TRANSMISSION PRICING APPROACH THAT IT IS PROPOSING AS PART OF THE STANDARD MARKET DESIGN?

A. No. As far as I know, FERC does not have any specific monitoring rules in place that are designed to monitor for any exercise of market power that would impact congestion prices charged for transmission. Thus far, I believe that congestion cost pricing for transmission is only operative in the PJM ISO, but it is scheduled for the other ISOs, as well. Unfortunately, since congestion costs that impact transmission prices are basically derived from local generation bids priced as explained above, all the weaknesses of the current set of monitoring rules for generation-related market power bode poorly for the likely ability of the ISOs or FERC to monitor for the impact of market power on congestion cost transmission pricing.

Q. DOES FERC HAVE ANY MARKET MONITORING AND MITIGATION RULES FOR USE IN LOAD POCKETS?

A. Yes, there are several load pockets in the Northeast, such as New York City and Boston, for which FERC has established market power mitigation rules, since it would be very easy for generation owners with units within each load pocket to exercise market power during times of high load. Basically, without getting into details, the approach that FERC has taken is to establish either negotiated or cost-of-service based price caps during hours when the generation owners within the load pockets would have monopoly pricing ability. One problem with this approach is that strategic bidding can usually lead to higher than competitive generation prices within load pockets long before demand within the load pocket rises so high that *monopoly* pricing is possible. The exercise of market power through strategic bidding could be quite potent well before monopoly pricing is possible. However, FERC has not properly addressed this issue yet, just as they have not found adequate ways to monitor for market power in the broader energy spot markets. The issue that the ACC will need to grapple with, then, is that load pockets like Phoenix and Tucson tend to facilitate the exercise of market power through strategic bidding, and thus it is even more important in a state like Arizona to have adequate means in place to deal with this likely problem.

SECTION IV – DIVESTITURE OF EXISTIING GENERATION PLANTS CURRENTLY IN THE APS AND TEP RETAIL RATE BASES

Q. WHAT ARE SOME OF THE POTENTIAL <u>ADVANTAGES</u> OF ALLOWING THE DIVESTITURE OF THE EXISTING GENERATING UNITS OF AEP AND TEP INTO UNREGULATED AFFILIATES OF THOSE UTILITIES?

A. Some of the potential advantages of allowing the divestiture of these power plants to go forward as contemplated under the Arizona restructuring rules are that eventually doing so could facilitate development of a competitive wholesale market, with one consequence being that this could lead to more efficient (lower) operations and maintenance costs for those units. In theory, such a development could lead to a larger number of retail providers of power directly to customers, and, therefore, a competitive retail power supply market in Arizona.

Q. DO YOU BELIEVE THAT IT IS LIKELY THAT SUDDENLY DIVESTING ALL OF THESE EXISTING POWER PLANTS TO UNREGULATED AFFILIATES OF THE SAME UTILITIES WILL LEAD TO THESE RESULTS?

A. No, I do not believe that the sudden divestiture of all of the power plants currently in the APS and TEP ratebases will lead to competitive wholesale or retail markets for electricity in Arizona. The main reason why I do not believe that this outcome is likely is that these APS and TEP affiliates would continue to own most of the generating units within Arizona, and, certainly most of the generating units within the load pockets in Arizona. This implies that the concentration of ownership of the generating units available and able to serve demand in Arizona would not change at all, and with such a large degree of ownership concentration, it is hard to see how a competitive market could ever develop in the region. This is true unless a large amount of this existing capacity was precluded from competing for market-based prices by having its output already committed in a long-term purchased power contract to serve Arizona load, prior to divestiture, just as APS has proposed to do with its existing and new generating units.

Q. WHAT ARE THE LIKELY DISADVANTAGES OF ALLOWING THE PLANNED DIVESTITURE OF ALL OF THE EXISTING APS AND TEP GENERATING UNITS TO GO FORWARD AT THIS TIME?

A. There are many likely disadvantages of allowing the planned divestiture to utility affiliates of all of the existing APS and TEP generating units to proceed at this time. These disadvantages include:

1. Divestiture could require that the ACC establish a more complex, least-cost competitive bidding process with sufficient constraints to guard against market power.
2. The ultimate regulation of the price of power from the divested plants, and all new plants or purchased power contracts, would fall to FERC, not the ACC.
3. It would be very easy for the utility affiliates to exercise market power unless most of the capacity were committed to Standard Offer customers under a long-term cost-of-service based PPA such as APS has proposed. Alternatively, divested plants would have to be divided

up among APS and TEP affiliates, and many third parties, as buyers in order to reduce the concentration of plant ownership in the state.

4. If a long-term PPA based on cost-of-service is not signed to cover all existing power plants, then the amount of the competitive transaction charge paid by ratepayers would have to be reconsidered in the next rate case, or ratepayers might pay twice for some stranded costs.

5. The divestiture of generation, implying a continuation of unbundling, may make it easier for FERC to claim legal authority to set retail transmission rates, and to establish energy spot-markets and congestion-cost pricing for transmission in Arizona.

6. Market pressures to reduce plant operations and maintenance costs could also reduce the reliability of these plants, and, thus, reduce system reliability. This might require the ACC to require a higher planning reserve margin for the UDCs in Arizona than if divestiture did not occur.

Q. PLEASE DESCRIBE WHY THE DIVESTITURE OF ALL EXISTING APS AND TEP GENERATING UNITS COULD REQUIRE THE ACC TO ESTABLISH A MORE COMPLEX BIDDING PROCESS THAN IF DIVESTITURE DID NOT OCCUR.

A. If divestiture occurs, the complexity of the competitive bidding process will depend to a significant degree on how much of the divested capacity is committed to Standard Offer customers under a long-term cost-of-service based contract similar to the PPA that has been proposed by APS for all of its existing generation. This is because if all of the existing generation is so committed, then the ACC does not need to worry about that capacity being used to contribute to higher market prices through the exercise of market power by APS' and TEP's affiliates which own that capacity. In contrast, if some of the existing generation is not contracted for on a traditional cost-of-service basis, then given the limited amount of IPP generation that can access APS' and TEP's loads, it would be quite easy for the APS and TEP affiliates that own the existing (and some new) capacity to exercise market power in two ways. They will be able to exercise market power when bidding into a "competitive" bidding process, due to the very limited number of alternative sources of power, and they will be able to exercise market power in spot market transactions. Needless to say, the potential for the APS and TEP affiliates to exercise market power will be greatly enhanced relative to sources of power that can physically serve the various load pockets within Arizona. Thus, if divestiture proceeds, the ACC will have to try to devise a more complex bidding process to make it much less likely that the APS and TEP affiliates would be able to exercise market power in the future, especially within load pockets.

Q. IS THERE ANY WAY TO MITIGATE THE MARKET POWER THAT APS AND TEP AFFILIATES MIGHT BE ABLE TO EXERCISE IF DIVESTITURE CONTINUES AND A COST-BASED PPA IS NOT ESTABLISHED FOR THE OUTPUT OF THE EXISTING POWER PLANTS?

A. Yes, a difficult and quite controversial way of mitigating the market power that the APS and TEP affiliates which own power plants could exercise is to establish a "true-up" accounting mechanism for a competitive transaction charge that APS and TEP would be allowed to collect after the next rate case for each company. This would work by adjusting the competitive transaction charge annually or quarterly, upwards or downwards, based on the revenues received by these generation affiliates. Thus, if the affiliates receive higher "market prices" than were initially assumed in setting the stranded cost payments for the existing generating units (through the CTC) due to their ability to exercise market power, then the CTC would be reduced, even if this meant the CTC might need to be a negative value if the competitive market prices were high enough.

If such a CTC adjustment mechanism were established by the ACC at each company's next rate case, then there would appear to be no incentive for the APS and TEP affiliates to exercise market power for a long as the mechanism were in place. However, this mechanism would have to stay in place for a very long time for it to be effective; in theory, it should last for the entire operational lifetimes of the existing generating units so that ratepayers continue to get the economic benefits of the relatively low-cost power in the current mix of generating units.

Q. REGARDING YOUR SECOND POINT ABOVE, WHY WOULD THE ULTIMATE REGULATORY AUTHORITY FOR THE PRICE OF POWER FROM THE DIVESTED GENERATING UNITS SHIFT TO FERC?

A. While I am not a lawyer, I believe that it is clear that since any power sales from the divested units to the Standard Offer customers would occur under a wholesale power contract or would occur in the deregulated wholesale market, these sales would be FERC jurisdictional. This is because most, if not all, wholesale power sales are FERC jurisdictional.

Q. WHY MIGHT THE FACT THAT THESE POWER SALES FROM EXISTING GENERATING UNITS WOULD BECOME FERC JURISDICTIONAL BE A PROBLEM FOR ARIZONA?

A. One of the types of problems that could arise if these power sales become FERC jurisdictional is that FERC might allow a much higher rate of return on these power plant investments compared to the traditional rate of return allowed by the ACC. This higher rate of return might easily be justified if the cost of capital to all IPPs is higher than the traditional cost of capital to regulated utilities as set by the ACC. This is likely to be the case in the future, especially in light of the recent financial crisis that the IPP industry as a whole is going through. I believe that in the future the financial markets are going to realize that the IPP industry is much more risky than they appear to have assumed in the recent past. However, even in the recent past I believe that the average cost of capital to IPPs was higher than that for regulated utilities.

Q. PLEASE EXPLAIN YOUR THIRD POINT ABOVE.

A. I have already commented on some aspects of point #3 above. However, one other way to mitigate the potential for the APS and TEP generation affiliates to exercise market power would be to divest a substantial amount of the existing capacity to other, third party IPPs. Of course, this would have to be done in a way to prevent the future re-aggregation of this generating capacity by one company. Conceptually, market power might be somewhat mitigated if many roughly equal-sized owners of generating capacity existed within Arizona, perhaps at least ten equal-sized owners. However, even if this could be done, the potential for market power within load pockets would still be high. To deal with this problem, the ownership of generation would have to be divided up quite broadly on a geographic basis, especially within load pockets to a large number of owners. For example, within load pockets, the ACC may need to limit generation ownership to one generating unit per company given the relatively small number of generating units within each load pocket. However, doing this could have the disadvantage of resulting in diseconomies of scale, which could increase electric market prices somewhat. This potential economic trade-off is typical of many of the economic trade-offs that arise when the issue of electric industry restructuring is carefully considered.

Q. PLEASE COMMENT ON YOUR FOURTH POINT ABOVE. WHY MIGHT RATEPAYERS PAY TWICE FOR SOME STRANDED COSTS IF NOT ALL OF THE EXISTING GENERATION IS SOLD TO STANDARD OFFER CUSTOMERS ON A COST-OF-SERVICE BASIS UNDER A LONG-TERM PPA?

A. My argument is addressed in part above, when I discussed the use of a competitive transaction charge adjustment mechanism to mitigate market power for that portion of the output of existing generating units that is not sold to standard offer customers under PPA. But this involves an even deeper issue. Without such an adjustment mechanism, ratepayers could pay twice for some stranded costs even if the market price paid for the generation output were a *competitive* market price, i.e., if market power were not being exercised. Market power will make it even more likely that ratepayers would pay twice for even more stranded costs.

To oversimplify slightly, stranded costs are defined as cost-of-service rates minus market prices. Years ago, most people assumed that stranded costs would always be positive (greater than zero), because market prices would be lower than cost-of-service based rates. However, this is not likely anymore for most utilities, and is not the case in Arizona, especially for APS. (Mr. Jack Davis' testimony in Docket No. E-01345A-01-0822 makes this point in different words.) Thus, stranded costs can be negative as they were projected to be in Colorado. Either way, if market prices in the future are higher than the level implicit in the current CTC charges in Arizona for APS and TEP ratepayers, then ratepayers will pay twice for the difference between the future market prices and the level implicit when setting the CTCs. Market power will tend to make this difference even bigger. If likely future market prices average higher than embedded cost-of-service based rates as Mr. Davis claims they will, and I agree, then stranded costs will be negative, and ratepayers would have to get a stranded cost *credit* (negative charge) on their bill if they are not to pay twice for some stranded costs. Because of this potential implication of the divestiture of TEP's and APS' existing generating costs, I believe that it would be best for Arizona ratepayers if divestiture does not occur. That would be the best way for the ACC to protect ratepayers against market power.

Q. WHY MIGHT A CONTINUATION OF RATE UNBUNDLING DUE TO PLANT DIVESTITURE GIVE FERC SOMEWHAT BETTER LEGAL GROUNDS TO CLAIM AUTHORITY OVER SETTING RETAIL TRANSMISSION RATES, AS WELL AS GENERATION RATES?

A. Again, while I am not a lawyer, I believe that FERC itself has claimed that when states shift from bundled retail rates under traditional rate regulation to restructured unbundled rates once generation divestiture occurs, they have clear authority to set all transmission rates within the state. I assume that one of FERC's arguments is that in this situation all generation sales become wholesale sales, certainly those to Standard Offer customers. Therefore, since FERC can set transmission rates for any wholesale generation sale, it can, in essence, set all "retail" rates within the state. In addition, this enhanced legal authority may also carry over into FERC's authority to establish RTOs, and all aspects of the Standard Market Design like spot energy markets, as I discussed above. This means, then, that all states like Arizona should carefully re-think any earlier decisions to unbundled retail electric rates and allow generation unit divestitures, if this allows FERC to displace the state PUC's authority to set retail transmission rates. Allowing plant divestiture may leave the state PUC with ratemaking authority only over distribution system and customer service charges related to distribution only. (I include metering as part of the distribution system.) However, I want to be clear that I am not supporting FERC's legal claims in the above statement, many of which appear to be controversial.

Q. WHY MIGHT MARKET PRESSURES CAUSE THE RELIABILITY OF THE DIVESTED POWER PLANTS TO DETERIORATE, THUS REQUIRING HIGHER PLANNING RESERVE MARGINS?

A. If the existing APS and TEP power plants are divested, and if their output is not provided under a long-term PPA, the new owners might attempt to maximize their profits, especially in the short run, by reducing their O&M expenditures below prudent levels. This reduction in expenditures might lead to higher forced outages rates due to more frequent equipment breakdowns. Higher forced outage rates would imply the need for a higher planning (and actual) reserve margin in order to keep system reliability at the same high level that it currently is.

However, there is an additional reason why the divestiture of the existing power plants, and having deregulated plants generally in the supply mix, might require a higher planning reserve margin. This could be necessary if power plant owners find it to be profitable to *withhold capacity* near times of peak demand in the market. Of course, as I mentioned earlier, FERC has already decreed that owners should not withhold capacity from the market. However, even if an RTO is established for the Arizona region, which would be necessary to enforce this anti-withholding rule, the RTO may not find it easy to distinguish illegitimate attempts to withhold capacity from legitimate planned outages for maintenance purposes. The New England ISO has already had to struggle with making these determinations for several years now, and the issue remains controversial in New England.

SECTION V – AFFILIATE TRANSACTION RULES AND CODES OF CONDUCT

Q. HAVE YOU REVIEWED THE ACC'S EXISTING AFFILIATE TRANSACTION RULES IN ORDER TO DETERMINE WHETHER THE CURRENT RULES COULD HELP IN PREVENTING ANY TYPES OF MARKET POWER ABUSE IN ARIZONA THAT WOULD RESULT FROM DIVESTITURE OF THE EXISTING POWER PLANTS?

A. Yes, I have reviewed the ACC's current affiliate transaction rules R14-2-801 through 806. In that regard, it seems to me that the sub-sections of these rules that are most directly relevant to the planned divestiture of existing generating units to utility affiliates are sub-sections R14-2-805(A)(5) through (11). Generally, these sub-sections require detailed information to be reported on the business relationships and the allocations of cost between regulated and unregulated affiliates. Interestingly, sub-sections (5) and (7) require "an assessment of the effect of current and planned affiliated activities on the public utility's capital structure and the public utility's ability to attract capital at fair and reasonable rates," and an explanation of the impact of the activities and structure of the company on these issues. These provisions may have some impact on assisting the ACC to understand the impact that divestiture might have on utility rates. However, I do not believe that there are any significant protections against the types of market power that I have discussed above in these affiliate transaction rules. The existing rules only provide some information that might assist the ACC in preventing cross-subsidies between the regulated and unregulated affiliates that could exacerbate market power, but they do not deal with the issues of capacity withholding or strategic bidding in deregulated power markets.

Q. WHAT IMPACT COULD DIVESTITURE OF POWER PLANT INVESTMENTS TO UNREGULATED AFFILIATES HAVE ON THE COST OF CAPITAL TO THE REGULATED PUBLIC UTILITY?

A. I believe that it is quite possible that if an unregulated affiliate of a public utility has trouble financing a sudden, new and large amount of investment, such as will be needed to finance all the existing power plants, this financial burden could spill over and increase the cost of capital for the regulated public utility, as well. Thus, if the ACC does proceed with the divestiture of all existing generation units owned by APS and TEP, it should carefully avoid passing on the impact of this kind of spillover effect to electric rates for regulated products such as distribution and customer service charges. In addition, the ACC should try to structure any wholesale PPA contracts of the type proposed by APS for its Standard Offer customers in a way that would maintain the cost of capital for the divested assets at the same level that it would have been under a continuation of retail rate regulation by the ACC. This would be justified so that the ratepayers do not bear the burden of any additional risk perceived by the financial markets in an unregulated affiliate owning such a large amount of unregulated assets. Thus, I suggest that the ACC take administrative notice in this docket of any reports that APS and TEP have filed with the Commission on or before April 15, 2002 in compliance with R14-2-805. If these two companies have not filed any, or adequate, compliance reports yet, I suggest that such filings be required, and be provided as quickly as possible. Clearly, the ACC needs these reports as part of its overall assessment as to what the consequences of divestiture are likely to be on retail ratepayers, and whether divestiture still is in the public interest in Arizona.

Q. HAVE YOU ANY COMMENTS ON THE RELEVANCE OF THE ACC's CODE OF CONDUCT RULE TO PREVENTING MARKET POWER?

A. Yes, the Commission's Code of Conduct Rule R14-2-1616 generally seems to be structured to attempt to prevent the cross-subsidization of unregulated affiliates by regulated utility activities. This is good, of course, but it also would not help in preventing other types of market power from being exercised such as strategic bidding, and gaming the deregulated wholesale electric markets, in general.

SECTION VI – CONCLUSIONS AND RECOMMENDATIONS

Q. WOULD YOU AGREE WITH THE ACC's MAY 2, 2002 ORDER IN THIS DOCKET THAT THE GENERATION DIVESTITURE ISSUE, AND ASSOCIATED MARKET POWER ISSUES, ARE EMERGING AS THE KEY ISSUES IN THE COMMISSION'S DELIBERATIONS AS TO WHETHER AND HOW TO PROCEED WITH ELECTRIC INDUSTRY RESTRUCTURING IN ARIZONA?

A. Yes, I do. It should be clear from my testimony above, and from the comments to FERC attached as Exhibit___(RAR-1) and Exhibit___(RAR-2), that whether and to what extent the divestiture of APS' and TEP's existing generation units to unregulated affiliates occurs, will have a major impact on the future of the electric utility industry in Arizona. From my perspective, however, there are many complex regulatory challenges facing the ACC that should be analyzed much more fully before divestiture is allowed to occur. Indeed, there are also cutting-edge analytical problems regarding the potential for the exercise of market power in Arizona's generation markets, and the impact on market prices of transmission constraints, which should also be solved before the Commission proceeds with divestiture. Yet, both the regulatory problems and the analytical problems are very complex, as I have tried to describe briefly above. A much more complete discussion of these problems is required beyond what I have had the time to draft here. Divestiture may also impact the regulatory authority of the ACC with respect to FERC, and, therefore, the full range of relevant legal issues that may be affected by proceeding with divestiture should also be thoroughly analyzed first.

Q. IN YOUR OPINION, WHAT IS THE MAJOR IMPLICATION OF THIS COMPLEX SITUATION IN ARIZONA FOR HOW THE ACC SHOULD PROCEED AT THIS TIME?

A. To me the implication of this very complex situation in Arizona presently is that the ACC should take either one of the following two options:

1. The preferable course of action for the ACC is to decide now <u>not</u> to proceed with the divestiture of APS' and TEP's existing generating units at all. The justification for this action is the long list of difficult regulatory problems and economic issues that I have described above that arise as a consequence of divestiture. This should certainly be the course of action taken if cost-of-service based PPAs are not firmly committed to for all the output of these generating units for standard offer customers.
2. If the ACC wants to maintain divestiture without PPAs as a regulatory option, then it should take more time to clarify and define all the relevant issues, and to then do all relevant legal and analytical studies that it believes are necessary to help it address the complex regulatory issues that it faces. In particular, I do not believe that divestiture can be accomplished properly by January 1, 2003. Thus, I believe that the Commission should delay the final target date for deciding whether or not divestiture should occur, and to what extent, until at least January 1, 2004.

The issues are too complex to be resolved within the current timeframe contemplated by the electric restructuring rules.

In addition, the Commission should re-examine the pros and cons of electric industry restructuring as a whole during the next year in light of the prior experience that other states have had with restructuring. However, it is likely to be considerably more difficult to establish competitive wholesale, and, therefore, retail electric markets in Arizona and most of the West than it has been in the East. Additionally, in most of the East, there still is no significant level of retail competition, and wholesale markets still suffer from the exercise of market power.

I will also remind the Commission that when the neighboring state of Colorado was considering whether or not to restructure its electric industry three years ago, it decided not to proceed primarily on the basis that since the state was projected to have net negative stranded costs, policy makers were concerned that deregulating generation would raise electric rates to consumers substantially in the long run. I believe that this could be the outcome of deregulation in Arizona, as well, unless the output of all existing generation units in Arizona remains committed to serving Arizona ratepayers on a cost-of-service basis for the indefinite future. Thus, the only conditions under which I can foresee that restructuring and divestiture might make sense in Arizona is if both APS and TEP sign long-term PPAs similar to the one proposed by APS last winter (with additional consumer protections).

Q. DO YOU BELIEVE THAT ARIZONA SHOULD APPROVE THE CREATION OF AN RTO <u>PRIOR</u> TO DECIDING WHETHER TO CONTINUE TO RESTRUCTURE THE INDUSTRY AND <u>PRIOR</u> TO DECIDING ON GENERATION DIVESTITURE?

A. No, I would strongly recommend that the ACC <u>not</u> approve the participation of Arizona utilities in a regional RTO until *after* the ACC has decided how it wants to proceed with restructuring, in general, and with divestiture of generation, in particular. In the meantime, I recommend that the ACC take all legal actions necessary to preserve its legal rights with respect to any new regulatory areas or initiatives where FERC may claim priority in matters affecting Arizona ratepayers. For example, I recommend that the ACC actively participate with comments in the upcoming debate over FERC's expected NOPR on RTOs and the standard market design for them in Docket No RM01-12-000.

Q. DO YOU BELIEVE THAT THE ACC SHOULD PROCEED WITH A COMPETITIVE BIDDING PROCESS FOR GENERATION PRIOR TO REVIEWING IN MUCH GREATER DETAIL THE LEGAL AND REGULATORY ISSUES THAT DIVESTITURE MAY IMPACT?

A. No, I do not believe that the ACC should proceed with a competitive bidding process until the whole issue of the pros and cons of restructuring is reviewed in detail. However, the ACC should consider the complexities involved in creating a competitive bidding process under a range of different scenarios with and without divestiture, in order to better understand all aspects of restructuring. While this is technically a Track "B" issue, whatever the Commission concludes about restructuring, the competitive bidding process must be, at its core, a *least-cost* planning process. The need for least-cost planning does not subside if the electric industry is restructured. It simply becomes one of the key functions of utility management and regulatory oversight that becomes more difficult to carry out because utilities are no longer vertically integrated. After all, even if Arizona proceeds to restructure the electric industry, the ACC still has the obligation to ensure that electric rates are as low as reasonably possible.

Q. WHAT IS THE MOST IMPORTANT LESSON FROM THE 2000-2001 "CALIFORNIA" MARKET EXPERIENCE FOR ARIZONA?

A. In my opinion, the most important lesson of the California experience with restructuring the electric industry is to *go slowly*. This is not a process that can be rushed. California did not even perform many of the relevant and important technical or policy analyses prior to restructuring its electric industry, thus it is not surprising that many mistakes were made. Also, we should not forget that some of the initial faulty suggestions made by California in designing their wholesale power markets were FERC approved. Arizona should take a careful and deliberate approach to electric industry restructuring, since the main goal of restructuring should be to maximize economic efficiency *in the long run*. Again, this process should not be rushed. In the meantime, if new generating capacity is needed to meet load, Arizona utilities can sign short-term or medium-term contracts for its acquisition.

Q. IN THE MEANTIME, SHOULD THE ACC SET A REQUIRED RESERVE MARGIN FOR PLANNING PURPOSES FOR ARIZONA'S ELECTRIC UTILITIES?

A. Yes, since it will be necessary for the ACC to establish a long-run required reserve margin appropriate for each utility that they regulate in Arizona whether or not restructuring proceeds, it seems to me that this effort ought to occur in parallel with the ACC's restructuring deliberations. Doing so will help to guarantee that system reliability will continue to be maintained at adequate levels throughout the state.

Q. IF THE ACC DECIDES TO MOVE AHEAD WITH ELECTRIC RESTRUCTURING AND GENERATION DIVESTITURE PRIOR TO THE FORMATION AND OPERATION OF AN RTO COVERING ARIZONA, HOW SHOULD THE ISSUE OF THE POTENTIAL EXERCISE OF MARKET POWER IN THE WHOLESALE POWER MARKET BE HANDLED?

A. If the ACC moves ahead with restructuring, and divestiture occurs by January 1, 2003, then the ACC will need to establish some other FERC-approved, independent body that would have the technical expertise and authority to monitor and mitigate market power in Arizona's wholesale power markets. Clearly, this function cannot just go unfulfilled if existing and new generation is deregulated.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX 1 - QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a B.S. in Physics and Philosophy from MIT, a M.S. in Physics from Columbia University, and a Ph.D. in physics from Columbia University. Currently I am a senior research director at Tellus Institute, as well as executive vice-president and secretary/treasurer of the Institute. I am also the manager of the Institute's Electricity Program.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF TELLUS INSTITUTE.

A. Tellus Institute is a non-profit organization specializing in energy, natural resources, and environmental research. Within Tellus Institute, the Electricity Program focuses on energy and utility research areas which include demand forecasting, conservation program analysis, electric utility dispatch and reliability modeling, least-cost utility planning and integrated resource planning, avoided cost analysis, financial analysis, cost of service and rate design, non-utility generation issues, bidding systems, incentive regulation, cost of capital analysis, and utility industry restructuring.

Q. PLEASE ELABORATE ON YOUR EXPERIENCE WITH ELECTRIC UTILITY SYSTEM SUPPLY PLANNING.

A. As past director of the Energy Group and manager of the Electricity Program, I have had wide experience assessing utility system supply options on both a service area and a regional basis. These assessments have encompassed all types of generation plant, transmission plant, purchases of capacity and energy, fuel purchases and contracting, central station district heating and decentralized cogeneration plants, and alternative sources of energy such as wind, biomass, and solar energy connected to electricity grids. These assessments have dealt with the technical, economic, environmental, regulatory, and financial aspects of supply planning, including the relationships between supply planning, load forecasting, rate design, and revenue requirements. I have also reviewed the prudence of many past supply-planning decisions by utilities.

Q. PLEASE PROVIDE A FEW ADDITIONAL DETAILS OF YOUR EXPERIENCE IN THE AREA OF UTILITY PLANNING.

A. Power supply system modeling and integrated resource planning has been a major focus of my activities for the past 22 years. My research and testimony in this area began in 1980, and I have testified in numerous cases involving generation planning and the integration of demand and supply technologies on a least-cost basis. For example, I submitted extensive generation planning testimony in the 1980 CAPCO Investigation in Pennsylvania in Case No. I-79070315, and in the 1981 Limerick Investigation as well (Case No. I-80100341). In early 1982, I prepared a major report for the Alabama Attorney General's Office entitled "Long-Range Capacity Expansion Analysis for Alabama Power Company and the Southern Company System," and I filed testimony in Docket No. 18337 before the Alabama Public Service Commission. In addition, I testified on the excess capacity issue regarding Susquehanna Unit 1 in the 1983 Pennsylvania Power and

Light Co. Rate Case (No. R-822169). In 1987, I testified before the Federal Energy Regulatory Commission ("FERC") on NEPOOL's Performance Incentive Program on behalf of the Maine Public Utilities Commission in Docket No. ER-86-694-001. In 1989, I testified before the Pennsylvania Public Utility Commission on excess capacity and ratemaking treatment regarding Philadelphia Electric Co.'s Limerick 2 nuclear unit. This work was performed on behalf of the Pennsylvania Office of Consumer Advocate in Docket No. R-891364. I also testified in Vermont in Docket No. 5330 on the cost-effectiveness of the proposed purchased power contract between the Vermont utilities and Hydro-Quebec. In the 1980s, I testified in several cases involving the planning and construction of the Palo Verde nuclear units, before the Arizona Corporation Commission ("Commission" or ACC), as well as before FERC.

Finally, in January 1998, I testified before this Commission on behalf of the Residential Utility Consumer Office ("RUCO") in Docket No. U-0000-94-165 regarding public policy recommendations on key issues related to calculation, sharing, and recovery of stranded costs; and presentation of the "retail generation service" methodology for computing stranded costs. In September 1998, in Docket No. E-01933A-98-0471, I was the author of comments to the Commission entitled "Analysis and Recommendations of Residential Utility Consumer Office Regarding the Tucson Electric Power Company's Stranded Cost Filing." In November 1998, I filed testimony before the Commission in Docket Nos. E-01933A-98-0471; E-01933A-97-0772; E-01345A-98-0473; E-01345A-97-0773; and U-00000C-94-165 on various filings related to the unbundled service tariffs, stranded cost recovery proposal for Arizona Public Service and Tucson Electric Power Company, and various other aspects of their restructuring proposals. I filed testimony before the Commission in Docket No. RE-00000C-94-0165 in July 1999 on the status of settlement discussions between RUCO and Citizens Utilities Company-Arizona Electric Division ("CUC-AED"), and summary concerns about CUC-AED's stranded cost recovery plans. In February 2002, I filed testimony before the Commission in Docket No. E-01032C-00-0751 on Citizens Communications Company's Purchased Power and Fuel Adjustment Clause and its wholesale power supply contract with Arizona Public Service.

Due to my extensive regulatory experience supporting the public interest, as outlined above, in 1988 I was chosen to serve a three-year term on the Research Advisory Committee of the National Regulatory Research Institute, an appointment made by the public utility commissioners serving on the NRRI Board of Directors. In addition, I have been the project manager on contract research that the Tellus Institute has performed for the U.S. Department of Energy, the U.S. Environmental Protection Agency, the U.S. Department of Justice, the National Association of Regulatory Utility Commissioners (NARUC), the New England Conference of Public Utility Commissioners, the New England Governors Conference, and the National Council on Competition in the Electric Industry.

In the last six years, I have spent most of my time analyzing electric utility restructuring issues. As early as 1996, I testified before the New Hampshire Public Utilities Commission on issues affecting the design of the state's pilot programs (Docket No. 96-150), and I testified before the New York Public Service Commission on stranded costs, market structures, and other issues related to ConEd's, NYSEG's, and RG&E's restructuring plans. I also have worked on or testified on other restructuring issues in Nevada, New Mexico, New Jersey, Illinois, Missouri, Colorado, Pennsylvania, Maryland, Maine, Rhode Island, and Michigan.

May 3, 2002

The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Electricity Market Design and Structure
(RTO Cost Benefit Analysis Report)

Docket Nos. RM01-12-000

Dear Secretary Salas:

Attached for filing via the FERC's Electronic Filing Program is an electronic file containing this transmittal letter, the "Comments of the Rhode Island and New Mexico Attorneys General and the Colorado Office of Consumer Counsel" and the "Certificate of Service" for the same in the above-referenced proceedings.

Thank you for your assistance.

Sincerely,

/s/

Janine Weitzell
Legal Secretary
New Mexico Attorney General's Office

cc: Service List

Enclosures

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Electricity Market Design and	}	
Structures: Options Paper	}	**Docket No. RM01-12-000**
And Standard Market Design	}	

**Comments of the
Rhode Island and New Mexico Attorneys General and
the Colorado Office of Consumer Counsel**

Sheldon Whitehouse, in his capacity as Attorney General of the State of Rhode Island; Patricia A. Madrid, in her capacity as Attorney General of the State of New Mexico; and Ken Salazar, the Attorney General of the State of Colorado, in his capacity as Attorney for the Colorado Office of Consumer Counsel jointly submit these Comments on the Options Paper and Standard Market Design in the above-captioned dockets.

Introduction

On March 15, 2002 the Federal Energy Regulatory Commission ("FERC" or "the Commission") issued a staff paper entitled *Federal Energy Regulatory Commission Working Paper on Standardized Transmission Service and Wholesale Electric Market Design* (the "Working Paper"). Based on the discussion in the opening paragraphs, the scope and objectives of the Working Paper can be summarized as follows:

- The Commission intends to reform all public utilities' open access transmission tariffs to reflect a standard market design ("SMD"). In particular, FERC proposes to extend coverage of a new transmission tariff, Network Access Service, to vertically integrated utilities providing <u>bundled</u> retail service. The Working Paper proposes a set of principles and policy decisions on SMD which will guide the Commission in developing the revised tariff, and in preparing a notice of proposed rulemaking that will be issued this summer.

- The objectives of the Paper are to "provide more choices…"(Working Paper, page 1)

In presenting these comments the FERC staff claim that "there is wide consensus today about the need to update the pro forma tariff and the basic elements of wholesale electric market design." (Working Paper, page 1) The staff even goes on to say that on some issues "there is clear consensus about what needs to be done," without stating what that consensus is. (Working Paper, page 1)

The Commission has requested comments on the Working Paper by April 10, 2002, but the parties submitting these comments could not complete their comments in that timeframe. However, on April 10, 2002, the FERC staff proceeded to issue a follow-on paper entitled "Options for Resolving Rate and Transition Issues in Standardized Transmission Service and Wholesale Electric Market Design," otherwise known as the "Options Paper." Since these two position papers are so integrally related, we have decided to file this set of comments on both documents simultaneously in an integrated fashion. This will facilitate FERC's ability to understand our position on these critical issues that will affect the electric utility industry for a long time to come. This document provides comments prepared by the staff of the Tellus Institute on behalf of our offices. For convenience, the detailed comments below are grouped under the same headings as the major sections of the Working Paper. The Summary and Conclusions sections address many general concerns raised by both papers.

We realize that many of the issues discussed in these papers have been discussed by FERC on many previous occasions. Unfortunately, we have not been able to comment on the previous incarnations of these ideas. However, in spite of the fact that FERC and FERC staff have discussed some of these issues for quite awhile, we find the ideas and proposals in the

Working Paper remarkably undeveloped and unclear, though the new Options Paper does help to clarify some of those proposals and options. In contrast, we strongly support the very lucid "Comments of the North Carolina Utilities Commission on the Standard Market Design and Structure Working Paper" that were filed in this docket on April 10, 2002. Our comments here are designed to further amplify and clarify some of those arguments, as well as to state our broader objections to several of the FERC staff proposals and options. Of course, we agree with many of the other concerns expressed in the filings of other parties who urged great caution before FERC should consider actually implementing any of these proposals, as will become clear in these comments.

Summary

First, FERC should not assume that there is any consensus at all to change the current structure of transmission service and of wholesale generation markets in any particular way, or, even, to change them at all. FERC may want to believe that there is such a consensus, but it is not true, as the North Carolina Commission has stated. No documentation has been presented at all supporting FERC's claim that there are such significant problems with the current wholesale OATT transmission tariff that state regulation of bundled retail electric service should be torn asunder, with unknown impact on retail ratepayers. And if there are any problems with the current wholesale transmission tariffs, modest reforms may be most appropriate, but FERC staff do not even discuss this option.

Second, it appears that many of FERC's proposals in these two papers are unlawful, unless compliance is purely voluntary. For example, it appears that FERC's proposal to require that all transmission service, including bundled retail transmission, be subject to the same FERC-jurisdictional tariff is unlawful, or is, at best, on very shaky legal ground, as the recent US Supreme Court Decision of March 4, 2002 upholding Order No. 888 makes clear. In addition, such proposals as the requirement to create a centralized power market or trading hub, to use locational marginal pricing ("LMP") for congestion management, and the requirement to force utilities to allow FERC to assign or allocate transmission rights to themselves even though these utilities own the transmission lines in question that are used to provide bundled retail service, appear to be outright unlawful. They appear to be unlawful, in part, because they clearly would extend FERC's authority into areas affecting the generation-related services and charges that both wholesale and retail utility customers would be required to purchase and bear, or they implicitly involve a taking of property and a potential diminution of service quality that is regulated by the states. Some of these proposals also seem to be contrary to the Pike County doctrine, as well as contrary to other provisions of the Federal Power Act, which limits FERC's authority to setting the rates for wholesale power sales, but not mandating the types nor the amounts of power that must be purchased by any customer or utility, at wholesale or retail. Generally, state public utility commissions have that authority and, as such, FERC is precluded from exercising such authority.

Third, many of the ideas and proposals described in this Working Paper do not appear to reflect the arguments that many parties have made in other on-going FERC dockets on these very same issues, such as Docket No. EL01-118-000. This is particularly true for SMD issues related to market power monitoring and mitigation. In this aspect, this Working Paper represents a step backwards in the sense that it encourages or forces parties to repeat arguments that they have made many times before, particularly with regard to the desirability and structure of deregulated wholesale generation markets, and how to monitor and mitigate market power. For example, the staff still does not correctly enumerate the various mechanisms for being able to exercise market power, as the Northeast Consumer Advocates and we have pointed out repeatedly. If the mechanisms for exercising generation-related market power are still not clear to FERC staff, then their proposed remedies for market power can not be adequate.

Fourth, the proposals dealing with the concept of Network Access Service were still extremely unclear in the Working Paper. These proposals were not clearly contrasted with current FERC and state regulations affecting the same transmission tariff issues in various parts of the country. Fortunately, the Options Paper does clarify some of FERC's proposals regarding Network Access Service, though the concept of Transmission Rights ("TR") is still so ill-defined that we do not believe that concept is useful as the basis for defining a product that could be tradable within a market, or for individuating one's rights to utilize transmission capacity.

Fifth, FERC staff still does not seem to appreciate the need for careful cost/benefit analyses to be performed for each aspect of these major regulatory changes that they propose. They may believe that these proposals will enhance the economic efficiency of the US electric system, but more solid proof is required. We note the recent fiasco connected with the rushed three-month ICF analysis of the costs and benefits of overall RTO formation, and remind FERC that, this time, a much more careful analysis and open process should be implemented. Needless to say, the criticisms of almost all parties filing comments on that RTO report were overwhelming. Furthermore, a key principle that must be applied when performing any cost/benefit studies is that least-cost planning and least variable cost dispatch, as could be achieved through alternative policy options such as establishing tight power pools around the country, provides the appropriate cost baseline from which to measure the costs and benefits of

RTOs and the proposed SMD. As we have said before, it is very difficult to understand, from an analytical perspective, how RTOs and the SMD will be able to enhance economic efficiency beyond what least-cost planning and least variable cost dispatch can achieve.

Finally, the key issue as to how these new transmission service proposals will lead to just and reasonable transmission rates under the Federal Power Act is not discussed at all in these two papers. For example, the Working Paper does not even discuss whether prices for TRs derived from auctions or from secondary markets would automatically be "just and reasonable" in staff's view, if they were significantly higher than traditional embedded cost-based transmission rates (i.e., if they were above a "zone of reasonableness"). Similarly, if very substantial congestion costs were imposed on either wholesale or retail transmission customers as a result of a bid-based market system for generation as proposed, such that the total transmission rate was far above traditional cost-based transmission rates, would those rates be just and reasonable? Our general conclusion is that the proposed SMD is an illegal attempt to impose the consequences of various aspects of deregulated generation markets on states that have opted to continue traditional, bundled cost-of-service rate regulation at the retail level. In fact, the proposed SMD may also be an illegal intrusion by FERC into price setting for wholesale transmission.

Again, given the suddenness with which these two very important policy papers were issued, and given the usual very short deadlines required for comments on these two papers, FERC seems to be trying to rush ahead without the requisite level of careful preparation when dealing with very complex issues such as these. As the North Carolina Commission correctly points out in their April 10, 2002 comments, FERC is "attempting to dramatically redesign the entire structure of the electric industry," and this redesign "is being undertaken without regard to the lack of evidentiary support for the proposed approach...and without regard to the absence of statutory authority supporting the imposition of such an approach on the retail customers of vertically-integrated utilities operating under traditional regulation." (page 11) It would be much more reasonable for FERC to first provide evidence as to the nature and extent of the problems they perceive with the existing OATT under Order No. 888, and to provide a description of the legal basis for various policy options, prior to wading into the technical details of how those options should be implemented. Any legal and legitimate regulatory solutions to well-documented problems must flow seamlessly from an adequate description of those problems.

A. The Need for a Single Transmission Tariff

The generation and transmission systems in various parts of the country are somewhat different. In particular, in more scarcely populated regions, most of the load is concentrated in relatively large, widely separated load pockets, which are served directly by relatively few generation units and transmission lines. However, even in more densely populated regions, load pockets provide a significant problem for the efficient use of the transmission grid. Therefore, the development and use of a SMD may create problems and have impacts of differing magnitudes within different regions, which may outweigh any benefits due to the resolution of "seams" issues and other concerns raised in the Working Paper.

With these points in mind we urge the Commission to take a more open-minded attitude, and to defer the decision to definitely create a SMD on a nation-wide basis until there is clear evidence that the benefits of a SMD would outweigh its costs. Again, the answer to this question can not be intuited; it needs careful study and analysis for every region of the country, just like the issue of the cost/benefit of RTOs more broadly. A careful cost/benefit analysis of each major aspect of the proposed SMD and the Network Access Service is necessary. The baseline for any such cost/benefit analysis should be the operation of the generation/transmission system on a least variable cost basis. With that baseline firmly established, then the impact of the components of the SMD can be compared to the current situation relative to system operations.

In addition, the type of system planning issues raised in the Working Paper and the Options Paper also need to be addressed. Here a least-cost planning baseline should be established, and then FERC staff should attempt to compare how the current regulatory framework is likely to differ from strict least-cost planning, versus how the proposed SMD is likely to change these planning outcomes. By least-cost planning we mean the minimization of the present value of revenue requirements (computed on a cost-of-service basis) over the relevant long-term planning period. Note that least-cost planning also must include equitable consideration of demand-side management investments, which is something FERC has never done.

At this point, we must question if FERC staff have made the case that the current set of transmission regulatory policies based on the OATT deriving from Order No. 888 is "broken," and, therefore, needs fixing? What evidence does FERC staff point to for reaching its conclusion that the current transmission tariff "impede[s] a seamless national transmission grid and the development of broad, fully competitive electricity markets," even if this issue were within FERC's jurisdiction? (Working Paper, page 2 – Note the absence of the word "wholesale" from the above quote.)

One of the first problems that FERC staff mentions is that the current tariff still allows a vertically integrated utility to "favor" its own generation relative to the generation of other generation owners because it gets to determine available transmission capacity ("ATC") and total transmission capacity ("TTC") on its transmission lines. Of course, as the North Carolina Commission points out, this is what utilities are supposed to do under both state and federal law to serve their native load. But beyond that, FERC staff's claim is probably not true as applied to utilities' retail sales functions. Most vertically integrated utilities buy and sell wholesale power with their neighbors when they can dispatch that power to serve their native load at a variable cost that is less than their next plant in the dispatch order. In such instances there is some sort of a split savings, win/win situation, that benefits both companies. That is how economic efficiency is currently enhanced under state and federal regulation. But even if vertically integrated utilities did not always avail themselves of the very cheapest power in their regions, that is a management prudence issue that the relevant state PUC would have the authority to review. FERC has no authority to dictate from whom, and when, any utility should buy power to serve retail load.

Second, FERC staff mentions that as the dependence of utilities on the wholesale electric markets grows "there are substantial competitive consequences and higher costs to all retail customers if we do not apply consistent, non-discriminatory rules to all transmission customers." (Working Paper, page 2) This may or may not be true, but FERC staff have certainly not documented whether it is true. It is just asserted.

Third, FERC staff note that more transmission transactions "are being curtailed under transmission loading relief (TLR) mechanisms that rely on non-price allocation methods," as if that were a clear problem. (Working Paper, page 2) However, the more frequent occurrence of TLR curtailments does not indicate anything about the economic efficiency of the operation of the transmission grid. All it indicates is that more people are trying to schedule transmission flows than the physical constraints in the system allow. In order for FERC staff to make the case that any particular TLR curtailment reflects economic inefficiencies in system operations, they would have to show that the dispatch in the region was not consistent with least variable cost dispatch, subject to physical transmission constraints, at the time at issue. In addition, FERC staff would have to allow for reasonable levels of contingency capacity on the relevant transmission lines (such as CBM), consistent with NERC's operational rules, so that regional reliability was not endangered. Thus, if they could show that the system dispatch was not reasonably consistent with a least-cost dispatch with proper application of NERC rules, then this would be evidence of a diminishment of economic efficiency. FERC staff's follow-on thought implying that the TLR-related problems are due to the fact that "congested transmission capacity is not being consistently allocated to the market participants who value transmission the most." is a completely unproven hypothesis.

Finally, FERC staff point to the fact that the existing tariff has flaws which "are allowing operational problems such as the "socialization" or "uplift" of congestion management prices across all customers in a region" which obscures price signals. This point also is irrelevant to whether or not there are operational problems. The presence of congestion does not indicate operational problems, and who pays for congestion costs is a rate design issue, which will always be contentious, whether at the wholesale or retail level. The socialization of uplift charges may be the best cost allocation if all parties pay these charges in approximate proportion to the degree to which they benefit from system redispatch. If not, an equitable allocation method is needed.

In fact, the presence of congestion may even be consistent with the utility system being operated in a least-cost manner, because it may not be economically efficient for the utility to invest in additional transmission to reduce congestion. Some congestion will always be present on electric grids. Nor is it clear that congestion cost pricing, even if it were legal for FERC to impose this approach on transmission used for bundled retail service, would be the most institutionally efficient means to incentivize least-cost planning for the joint transmission/generation system. Most state PUCs require least-cost planning for these purposes anyway, and if they do not, that is a much more manageable reform that FERC and other regional bodies could encourage states to implement, without taking away any of their authority. Any regional transmission planning will always be contentious, and the process should be improved, but that fact has nothing to do with claimed inadequacies in the current OATT. Better congestion price signals will not help. Better least-cost planning, with regional cooperation with regard to facility siting, will help.

In fact, we do not find that the current OATT has engendered significant problems for wholesale transactions within our states. Thus, we do not find that FERC staff has successfully made their case that the current problems with the OATT are so serious that the entire system of regulation for both wholesale and retail uses of the transmission grid need to be changed. In fact, we find the current OATT to be a fairly satisfactory and straight-forward way to price wholesale transmission services, especially since the current Network Service tariff under which wholesale power purchases to serve native load is priced is quite fair.

The Working Paper uses the term <u>transmission provider</u> to refer to an <u>independent</u> entity required to perform a variety of functions currently performed by RTOs, ISOs, or vertically-integrated utilities. Creation of such transmission providers where they do not currently exist will entail a major effort that may not be economically justified, especially in states where most utilities remain vertically integrated. Furthermore, there does not appear to be a legal basis for FERC to order establishment of an independent entity to operate the portion of the transmission system which is designed and operated for the benefit of the retail customers of the transmission system owner. As discussed below, the roles and powers assigned to these transmission providers could also create serious federal/state regulatory conflicts, even if it were legal for FERC to mandate their establishment. Thus, FERC should seriously reconsider whether it wants to initiate what are likely to be intense legal battles with many states over the issue of whether the Federal Power Act gives FERC the authority to regulate transmission provided for bundled retail customers, or even for other intrastate transactions that are unbundled. After all, section 824(b)(1) of the Federal Power Act prohibits FERC from exercising jurisdiction over "facilities for the transmission of electric energy consumed wholly by the transmitter," by which we assume the word "consumed" is meant to stand for retail sales made by the transmitter in the same state. This provision would, then, preclude FERC jurisdiction over bundled retail transmission.

In addition, there is another major problem with FERC's proposed vision of an independent transmission provider. FERC intends that the independent transmission provider would "administer the imbalance energy markets that are to be part of the standard market design." (Working Paper, page 5) Thus, FERC is not content with mandatory jurisdiction over retail as well as wholesale transmission pricing, but FERC intends to mandate deregulated generation markets for the "energy balancing function" of each utility. However, this proposal again seems to be aimed at a major overhaul to electric utility institutions which is intended to fix a non-existent problem. We are not aware of vertically integrated utilities that have sufficient capacity reserves having significant problems in balancing energy flows between control areas. Vertically integrated utilities have traded power within their regions on a short-term basis for decades. And these trades have been generally at or near the variable costs of production. These traditional, cost-based trades between vertically integrated utilities have the strong advantage that they make it very difficult for market power to infect the price, even if, technically, they have recently been granted market-based ratemaking authority from FERC.

However, once formal energy balancing spot markets of the type described by FERC in the Working Paper are established, the whole situation can change in quite dramatic ways, as the high prices in all four formal ISO-operated spot markets that have occurred periodically over the last three years have illustrated. If states want to participate in such wholesale energy markets, that is their right under the laws of each state, but such participation in deregulated wholesale electric markets should not, and can not, be required by FERC. The Pike County exception means that FERC can not dictate to utilities and states the quantities and sources of wholesale power that utilities must purchase for making retail sales. If the state or utility decides to purchase at the wholesale level, then, clearly, FERC has jurisdiction over the price. But FERC can not order utilities to buy from or, therefore, participate in deregulated wholesale energy balancing markets, unless each state PUC grants that permission, when required by or allowed by state law. Again, FERC has no authority to require that any specific type of wholesale power purchase be made by any utility in the US.

As noted above, the Working Paper also reflects a clear bias regarding the way in which transmission system usage should be allocated among consumers. On page 2, the Working Paper states that many transmission transactions are currently being curtailed based on "non-price allocation methods," as if this is clearly problematic. Again, as noted above, the Working Paper proceeds to complain that "congested transmission capacity is not being consistently allocated to the market participants who value the transmission the most." The point we want to make is that access to many essential services like medical care is also not allocated according to those who would pay the most, nor should it be. The staff then complains about cases where congestion costs are "socialized," thereby obscuring "the potential for price signals to indicate where new generation, demand response or transmission is needed." (Working Paper, page 2) In contrast, FERC should consider it an entirely open question as to the proper mix between allocating transmission system usage by non-price versus price considerations in an economy where electric service is an essential good for all members of the population. This is one of the many issues that the strict use of locational marginal cost pricing would raise, and is one reason why we have regulatory agencies that can incorporate important social policy goals into any industry pricing structure. Relying solely on market mechanisms can not perform this function.[1]

The bias of FERC staff towards the use of market-based price signals to enhance the economic efficiency of transmission grid operations is very clear on page 5 of the Working Paper, where the data from the table on page 4 is discussed. This data shows that New York has more congestion proportionately than does PJM. However, one can not assume, as FERC staff does, that this necessarily implies that the New York State grid is not well run. Nor does the

[1] Not only does FERC staff appear to be biased in favor of relying on LMP and other pricing mechanisms for the purpose of allocating transmission system usage, but they seem to merely assume that the use of single-price auction energy markets for the purpose of determining the LMP prices will lead to the most economically efficient outcomes. Unfortunately, this is not correct on technical grounds. The use of single-price auction generation markets distorts planning outcomes relative to strict, mathematical least-cost planning outcomes. This is because fixed and variable costs get conflated with each other in such markets.

presence of high congestion costs necessarily imply that there is any undue discrimination, nor any unjust and unreasonable pricing in New York State. Nor can one automatically assume, even if it is likely, that a proper least-cost planning study would demonstrate that new transmission lines would be cost-effective in New York State. What FERC staff does not seem to recognize in general, and this emerges clearly on page 5, is that the proper standard to which the efficacy of market-based mechanisms should be compared is a least-cost planning-based standard, as we have discussed above. If FERC is going to commit the US to a set of transmission/generation system policies that rely much more strongly on market-based mechanisms, they must show why such mechanisms would likely be better than state/regional least-cost planning efforts in arriving at least-cost system outcomes. This is the only reasonable standard. Proof of FERC staff's oversight in this regard is the fact that the term "least-cost planning" does not appear in this entire Working Paper, even on page 21 where long-term planning is discussed. What this omission implies about FERC's proposed policies more broadly, is that FERC does not have a clear conception of the planning and system operating goals that it should be aiming to achieve.

B. General Principles for Standard Market Design

The Working Paper states eleven principles which together are supposed to guide the development of a SMD. Principle 1 is, of course, completely appropriate, and quite positive. However, stating that all customers should be able to benefit from an efficient competitive wholesale electricity market even if the state in which they are located has not elected to adopt retail access, is quite different from saying that all utilities must participate in one. Similarly, principle 2 which states the hope that a SMD will reduce transaction costs relative to non-standard market designs ignores the other possibility; namely, that establishing FERC's vision of a SMD will be far too expensive, for many other reasons. Principles 3 and 4 are quite reasonable; however, there are potential conflicts among the principles. For example, is fostering accommodation and the expansion of choices for buyers and sellers in energy markets as stated in principle 5 always desirable? To the extent it is desirable, is not the authority to decide these issues vested in state public utilities commissions, and not in FERC, where retail sales are involved, even if a state has established retail access and unbundling? Forcing states and utilities to participate in certain generation-related markets including congestion markets does not facilitate "choice," it becomes a requirement. Also, how is the complexity involved in implementing FERC's vision of a SMD to be balanced against the need to have market rules that are fair, efficient, and understandable to all as required in principle 4?

Principle 7 makes a major assumption that the kind of price signals that reflect the time and locational value of electricity could facilitate short-term economic efficiency, which justifies requiring LMP markets. First of all, FERC's regulatory policies should support long-term, not short-term, efficiency, and sometimes there are conflicts between the two. Long-term economic efficiency will not be greatly influenced by hour-by-hour price signals. Long-term economic efficiency will be best enhanced by a regional transmission planning and expansion process, as FERC also mentions. However, what FERC omits in principle 7 is that this must be a least-cost planning process, and a least-cost transmission planning process implies that the process must simultaneously include generation planning so that the joint costs of transmission and generation can be least-cost to consumers over the long run. Short-term transmission price signals will be of little use to accomplish this goal. This planning process can not be left to market mechanisms. Thus, principle 7 must be changed substantially to incorporate an appropriate long-run least-cost planning perspective.

Principle 8 is also unobjectionable, but the presence of price-responsive demand should not be assumed to significantly prevent market power. Given the relatively low value of the short-term price elasticity for electricity, price responsiveness in the short-term is always likely to be quite modest. Therefore, it will have a modest impact on mitigating market power. Principle 9 is also appropriate. Principle 10 is very important, because native load customers of all utilities, whether they have unbundled transmission from generation or not, need to have their current level of service quality maintained. The basic rule that should be incorporated into principle 10 is "do no harm." However, this rule should also apply to the prices that current native load customers pay for transmission services, as well as to the quality of service. Any new transmission tariff adopted by FERC should not imply or allow for an increase in transmission costs for native load customers. A new transmission tariff should result in greater economic efficiency, as its main justification. If a new transmission tariff is more economically efficient than the existing OATT, then, if anything, it should allow for price reductions for all customers. However, there is a great danger that FERC's new transmission service as proposed in this Working Paper will increase prices for some customers. If FERC does not believe that this is true, it must demonstrate this result through quantitative examples that apply to different regions of the country. If there is transmission capacity that is truly not needed to maintain system reliability for native load customers, then it certainly could be made available for use by others.

Again, one of the most fundamental problems with FERC's presentation in the Working Paper is that to our knowledge, under the Federal Power Act, FERC has never had authority to decide what kinds of retail or wholesale purchases of electric power customers, or load-serving entities, should make. In light of this fact, it is quite strange that there is no discussion at all in these principles as to whether FERC has the legal authority to require utilities to participate in the types of generation-related markets proposed. Even if participation in these markets is voluntary on a state's part, as it is in the Northeast, the eleven principles will need to be applied in a balanced and careful fashion, taking due note of the specific needs of each sub-region of the country. The key assumption made by all of the principles is that deregulated wholesale generation markets of some form or another should exist, and that they will yield more economically efficient outcomes. That is a key assumption that, again, must be demonstrated by FERC, and not just asserted, especially since FERC-approved market monitoring and mitigation rules have not been able to prevent substantial amounts of market power from being exercised in the past.

(1) Congestion Cost Pricing

This section focuses on principle 7, because the issue of how to charge for the impact on system costs of congestion is so potentially problematic, even in those states where retail access has been established. Principle 7 proposes the adoption of Locational Marginal Pricing (LMP) as a basic feature of the SMD. The central issue that arises in connection with the LMP proposal, as we discuss below, is that it is a market-based approach to pricing transmission, rather than a cost-based approach. It is also an approach that could lead to double charging for congestion costs, if the proposal is not crafted carefully. This could occur by customers being charged for congestion once through the prices they pay for transmission, and once through the prices they pay for generation. In considering the impact that LMP might have, the following specific points need to be considered:

- As shown in the PJM and NY data provided in the Working Paper, transmission is only about 10 percent of generation and transmission costs which, in turn, are about 70 percent of an average customer's bill. With a short-run price elasticity of demand of -0.2 (a figure suggested by the literature), a 1 percent increase in transmission costs should lead an average customer to reduce usage by about .014 percent. In the short run, then, even doubling transmission costs would only reduce usage by about 1.4 percent, not a significant impact. Thus, price signals due to LMP are not likely to have much influence on usage of the transmission system.

- LMP could create inappropriately high transmission <u>prices</u> at certain points, especially during times of peak demand when generation bids may be very high due to the exercise of market power. Yet, the actual <u>cost</u> of congestion might be much lower at those times. This outcome might appear to provide an incentive for the construction of generation at, or transmission to, those points. However, if such construction occurs and "solves the problem" (i.e., reduces LMP), the ability of generators or merchant transmission line owners to obtain revenues based on high LMP prices vanishes. Also, the high prices would be deceptive, and might stimulate construction of uneconomic new lines. At best, then, the price signals due to LMP can only provide <u>clues</u> as an input to the transmission planning process, because they do not provide direct financial incentives in the form of actual cost recovery, nor do they accurately reflect real economic costs. In contrast, cost recovery for new transmission subject to cost-of-service regulation is unaffected by the variability of congestion costs.

- An LMP-based pricing scheme can draw attention to congestion, but can not "manage" it. Congestion will likely be present to almost the same degree with or without an LMP system, if a system for charging for congestion is economically efficient, due to the low price elasticity of demand relative to changes in transmission costs. In fact, relying on price bids and not true economic costs for pricing transmission usage will make for less economic efficiency. This is because the economically efficient outcome for managing congestion can be derived by assuming least variable cost dispatch and compliance with NERC system operation/reliability rules for transmission capacity contingency allowances. An LMP-based system for charging for congestion can not do better than this, by definition of economic efficiency. In fact, it is doubtful that LMP can do as well, because LMP provides an after-the-fact price signal. Thus, the LMP-based approach will not actually determine how the transmission system will be operated hour-by-hour. Of course, the proper management of congestion also requires the development of DSR and energy conservation programs, as well as an effective and efficient planning process to site and construct needed generation and transmission facilities, as discussed above, on a least-cost basis.

The major problem, then, with LMP is that it is based on price bids for generation, and not on true costs. To the extent that price bids are above the variable costs of production, they will lead to a potentially economically inefficient dispatch of the generating units, especially if the bids cause the dispatch order to change from what it would have been under a least variable cost dispatch. Price bids above cost will also lead to incorrect price signals for transmission system planning purposes, and, therefore, will prevent least-cost planning outcomes. Price bids above costs will also lead to overcharges for transmission usage. So it is not clear that an LMP-based approach to pricing transmission can serve any useful function at all because it is a bid-based system, not a cost-based system. This would be true unless FERC limits the generation price bids to the actual direct variable production costs which they have so far refused to do to mitigate market power.

The other danger with an LMP-based approach to pricing transmission is that the market clearing price within a congested area will be charged for all power transmitted into that area, even if much less power was generated by the unit which cleared the market within the area. For example, if the market clearing price within a load pocket was $100 per MWh because 10 MW of a peaker had to be run out of merit order given transmission constraints, then the $100 per MWh price should not apply to any more than 10 MW of power being transmitted into that load pocket at the time, even if 100 MW was being imported. This error would be made if the single price auction approach to determining market clearing prices for use by an LMP approach obscures the details of the real dispatch and the costs of the generating units which actually serve the load pocket. This would be one way in which congestion costs might be over-recovered. Clearly, in order to avoid the double recovery of congestion costs, which would contribute even more to economic inefficiency, the actual level of incremental variable costs caused by the out-of-merit dispatch should only be charged once. Traditionally, load-serving entities within a load pocket would naturally be charged for congestion costs because they would have owned the necessary amount of generation capacity inside that load pocket to meet peak load when the transmission lines into the load pocket became congested. Thus, the load-serving entities would have had to pay the incremental dispatch costs for the out-of-merit dispatch, because those incremental costs would be the variable costs of their own power plants. This is similar to recent problems within the New England ISO where NEPOOL has been charging all load serving entities for uplift charges (congestion costs), even when the load serving entity has been self-supplying its own power through bi-lateral contracts, which themselves include the costs of avoiding congestion.

Even more fundamentally, FERC does not have the legal authority to impose a bid-based LMP scheme on any vertically integrated utility for the purpose of determining the price of transmission services charged to retail transmission customers. First of all, FERC would have to make sure each LMP price at the wholesale transmission level was just and reasonable under the FPA, something it has yet to do even in the PJM region where LMP pricing has existed for some time. However, since LMP prices are derived from generation unit costs; namely, the costs of redispatching the generation system in certain ways, and not from transmission system costs, LMP becomes a type of generation service.

Not only does FERC have absolutely no legal authority to mandate that any utility purchase this type of generation redispatch service, even at the wholesale level, while it may have the authority to set the price <u>if the service is purchased</u>, it certainly does not have the legal authority to force providers of retail transmission services to also pay for these generation services if they do not want to purchase them. After all, most vertically integrated utilities do not even need this type of generation service (redispatching other generation owners' plants to minimize congestion) because they have already planned their own generation systems so that they own generation units in appropriate locations to reasonably minimize congestion through use of their own facilities. Certainly, FERC can not require vertically integrated utilities that have managed their congestion in the past by using their own power plants, to pay for the redispatch costs of other generating units, if they do not want to purchase that service as part of a least-cost plan for operating their system. This FERC staff proposal for LMP illustrates the complex type of jurisdictional problems that can arise if two different types of markets or services are intrinsically coupled together and priced together, such as transmission and generation. The concept may be aesthetically pleasing at some abstract level, but it may simply be unworkable and illegal.

(2) Resource Neutrality

Principle 6 states, in part, that market rules must not unduly bias the choice between demand and supply resources, or among choices of fuel consumed by generating units. In fact, there are good reasons to require more favorable treatment for demand-side resources, including Demand Side Response (DSR), in a fair planning process. These reasons include the avoidance of environmental emissions, the enhanced ability to respond to reliability problems, and possible reductions in market power.

The savings to customers associated with DSR if a deregulated spot market has been created may be sufficient to justify higher payments to DSR providers than just avoided variable costs. If DSR lowers the market clearing price determined by a single price auction as in New

England, the savings to customers will be much more than the cost of the avoided supply. Thus, for example, in an hour where demand is 10,000 MW, the market clearing bid is $100 per MW for 50 MW, and the next highest bid is $95 per MW, 50 MW of demand reduction in a single price auction market produces savings of $100 x 10,000 - $95 x 9,950, or $54,750—not only the $5,000 that would be paid to the last 50 MW dispatched without DSR. Of course, the savings to ratepayers depends somewhat on the degree to which changes in revenues in the energy market affects bids and market clearing prices in the capacity market.

Recent studies, such as *Retail Load Participation in Competitive Wholesale Electric Markets* by Hirst and Kirby, show that high prices are required to draw demand-side resources into the market, unless a minimum level of such resources is set by regulation. In light of these studies, the Commission should indicate that, as a matter of policy, it is appropriate to share the savings produced by DSR to some extent between the providers of DSR and the purchasers in electric spot markets who realize the savings, depending on the precise market structure adopted. However, state PUCs should have the final authority regarding resource planning.

Finally, FERC should be aware that DSR can mask the exercise of market power as well as help in combating it. For example, in the illustration above, if both the $100 and $95 bids reflected market power, DSR could mask the market power in the second bid. Success in fostering DSR to reduce market prices should not be taken as evidence that market power still does not taint the reduced price.

C. The New Transmission Service

This section begins by trying to clarify the "machinery" required for the Working Paper's proposed approach to transmission pricing via a new type of transmission service. Day-ahead and real-time markets for energy, as well as regulation service, operating reserves, and transmission services, are required. These markets are complex, involving multi-part bids for energy. Issues related to the workability of these energy markets will be discussed in Section D. below. Here the focus is on the general structure of the transmission service which the machinery is supposed to support.

The Working Paper introduces the concept of Network Access Service (NAS) under which <u>all</u> transmission service would be obtained, including that for bundled retail service. (Of course, just the fact that bundled transmission service prices would change would require these rates to be unbundled at least for computational purposes.) Due to the acknowledged lack of detail in the Working Paper and the number of key issues left open there for future discussion, FERC staff filed the Options Paper a few weeks later. Based on both papers, the general features of the proposed NAS appear to be as follows:

- All parties seeking transmission services are considered NAS customers, and so pay an access fee or charge designed to fully recover the embedded costs of the transmission system. How that fee might be assessed is discussed in the Options Paper. Payment of the access fee would give the customer Access Rights.

- All NAS customers can schedule transmission between any source and sink of power. They can use a kind of network service between the source and sink, or they can request a flowgate service which precisely specifies the transmission facilities that would be used, and to what degree. All customers pay the losses associated with the transmission service specified.

- Customers can achieve price certainty for transmission between specific sources and sinks by buying or holding Transmission Rights (TRs) for the service sought. These TRs could also be traded in a secondary market. In fact, the TRs must be made available to the secondary market if the initial owner does not need them. The ownership of TRs would preclude the need to pay congestion costs. How the initial distribution of those rights might be accomplished is also discussed in the Options Paper. FERC claims that their intent is to preserve the existing rights of the current users of the transmission system.

- Customers without the TRs covering transmission between a source and sink can still schedule transmission between those nodes if such transmission is physically possible, but will be liable for congestion charges. This contributes to uncertainty in pricing this transmission. These congestion charges would be paid to holders of TRs that were not fully utilized. The charges for each transmission path will be raised sufficiently to balance supply and demand for transmission service, if the initial demand for transmission capacity exceeds the transmission capacity, leading to the potential for congestion. This provision seems to imply a market-based system for allocating TRs, which will likely conflict with FERC's stated intention to preserve the existing rights of current transmission system users.

In order to comment fully on the NAS framework, a much more complete and detailed proposal for the framework would be required, in spite of the additional material provided in the Options

Paper. However, assuming that the preceding description is generally correct, a few comments can be made at this time:

- The existing transmission system has owners and traditional users. These owners should be the natural recipients of any TRs associated with the existing transmission system that are needed to serve their traditional native load customers on a reliable basis. Ample capacity benefit margins (CBMs) would need to be allowed for, since large power plants can go down on forced outages at any moment. There should be no auction or other mechanism of assignment of TRs that forces these owners to accept what functionally would be a buy-out of their transmission property rights, if the owners need to use these TRs to serve retail load. Where the owners are vertically-integrated utilities, FERC will need to work with state regulators to ensure that retail ratepayers' interests related to utility use of TRs are preserved according to the "do no harm" principle enunciated above. Only unneeded TRs should be distributed to other users of the transmission grid taking adequate levels of capacity benefit margins into account.

- It is not at all clear that the concept of Transmission Rights itself is a workable concept on a "network" or "source-to-sink" basis. The critical problem is that loop flows, which are inevitable to a considerable extent, will inevitably make application of the concept very difficult. In addition, transmission system conditions change by the minute as power plants change their output, and as demand changes, even if the transmission lines themselves are not subject to forced or maintenance outages. The changes in flows on any given transmission line necessarily create changes in the transmission capacity on every other line in its neighborhood. These loop flows serve to compound the problem of how to define an individual TR on a source-to-sink basis, because the uncertainties in how neighboring lines will be affected are so big, since this depends on which other power plants are operating. Thus, it is not clear that Transmission Rights on a source-to-sink basis could be specified precisely enough to be able to market such a property right or product, because the nature of the product will change in unpredictable ways at unpredictable times. Given these realities, creating a market for network transmission service will likely be far more complex than creating markets for kWh of energy or kW of generating capacity, which is difficult enough even when the definition of the product is crystal clear. Fortunately, creating such a market in transmission rights seems totally unnecessary given the benefits of the existing OATT.

- Even in the case of flowgate Transmission Rights, the capacity of any particular transmission facility will not be constant over time. This makes it very uncertain as to what total level of flowgate rights could be assigned to such a facility at any given time for the purpose of establishing TRs. Furthermore, even if a relatively fixed number of megawatts of flowgate TRs could be determined for a particular transmission line, transmitting power between two points would almost always require more than one line, and it may not be possible to be sufficiently precise about all the other individual flowgate TRs need to accomplish even a single point-to-point transaction over the course of a year for the customer to know what set of flowgate TRs they would need to be purchased to accomplish their goal.

- The notion that raising the access charges sufficiently to always be able to balance demand and supply in the transmission market for TRs is highly suspect, if the resultant prices are to remain just and reasonable under the Federal Power Act. Given realistically low short-term price elasticities, as discussed above, the access charge may need to be raised to unjust and unreasonably high levels for this balancing to happen, thus imposing a huge burden on native load customers. Such an approach as proposed by FERC would certainly not be consistent with our proposed "do no harm" principle. If and when the transmission market does not balance when access charges are maintained at just and reasonable levels, there needs to be a transparent and equitable mechanism for deciding whose request for NAS takes priority. This will likely be the usual situation when a non-price allocation system will need to be used to determine transmission system usage. Those transmission owners that need the TRs to serve native load should get first priority, as they do today. In fact, FERC stated its intention to preserve existing transmission capacity owners' rights, so this recommendation is completely compatible with FERC's stated intentions. Thus, a price-based allocation system for transmission system usage is very likely to be incompatible with maintaining just and reasonable rates, and is especially likely to be incompatible with doing no harm to native load customers.

- The Working Paper requires the creation of point-to-point and flowgate FTRs as both obligations and options. This is a secondary point. As pointed out, for example, in Dr. William Hogan's recent paper *Financial Transmission Right Formulations*, this requirement goes beyond what is currently implemented by existing ISOs. However, one major consideration is that one of the important lessons thus far of the deregulation of electric generation is the law of unintended consequences: what actually happens may be dramatically different from what was intended or hoped for. The California and Enron debacles are examples of this law in action. Requiring the adoption of a complex and expanded market system of TRs for the entire US without any regional experience is an invitation for this law to operate again.

Response to Options Paper Questions

Here we provide FERC with input on the list of options for various transmission-related issues raised on pages 6 through 13.

1. Who pays the access charge for deliveries within the transmission provider's system?

All transmission users should pay for their use of the system in proportion to their usage, as the current OATT provides. FERC has not yet justified the need for changing the current OATT to create an access charge and Transmission Right approach, as opposed to an after-the-fact system for allocating revenue requirement to users of network service. Therefore, an access charge approach should not be used.

2. Should the access charge apply to exports and wheel throughs?

Users of the transmission system who export and wheel through should pay for transmission on the basis of a point-to-point tariff similar to the one in place today. If there is a basis for modifying the current point-to-point tariff in any particular region of the US, this should certainly be discussed in that region. Ideally, transmission tariffs should be equalized across neighboring regions to facilitate market entry, as long as significant cost-shifting for native load customers can be avoided. These issues will need to be resolved on a regional basis. A lower transmission charge for wheeling out or through could only be justified if the transaction clearly placed a lesser burden on the relevant transmission system than the typical use of that system for native load customers. However, this is not likely in most situations, again because of loop flows and benefits that the entire transmission system provides to each of its users. Transmission system usage is very difficult to disaggregate for the reasons cited above, and therefore almost all, if not all, users should pay for their usage on a system average basis, e.g. within a given month, as they currently do.

3. Should the access charge be billed based on peak load or total usage?

We support a continuation of the current practice of allocating revenue requirements based on monthly coincident peak usage. Again, an approach using access charges should not be adopted.

4. How should the transition of transmission customers of existing wholesale contracts and bundled retail customers to the proposed revised pro forma tariff be handled?

The revised pro forma tariff should not be adopted as proposed. The existing OATT should be continued until such time as FERC can clearly demonstrate that the problems that they claim exist with the OATT exceed the potential problems with the new proposed pro forma tariff. This presents FERC with another difficult analytical task. In addition, whatever approach FERC ends up taking, the details of each type of tariff should be tailored to the situation and needs of each region of the country even though the basic design principles should be the same nationally.

5. Should historical customers get the initial Transmission Rights?

The approach to allocating transmission system usage by setting up marketable Transmission Rights should not be used. The operation of the transmission system should be left to the system operator of each ISO, RTO, or control area. That system operator should develop fair priorities for use of the transmission system based on the principle that native load customers receive the highest priority in order to prevent blackouts. The Transmission Rights approach should not be used because such a right inherently can not be defined sufficiently so as to adequately describe a marketable product. Thus, neither an initial auction, initial allocation, nor a secondary market are possible. If FERC staff believe that they know how to sufficiently individuate TRs from each other, they should issue another paper to describe this procedure as soon as possible. Otherwise, the TR approach should be abandoned.

6. If existing customers are given the initial conversion rights, how should Transmission Rights be allocated?

See the answer to question #5 above. If a TR approach is attempted, the transmission owners and customers holding existing transmission contracts should receive all the

TRs they require in order to adequately serve native load and to fulfill the rights that exist under current transmission contracts. This allocation of TRs will need to include, as noted above, sufficient TRs to satisfy all capacity benefit margin and NERC regional reliability requirements. In addition, a transition to a regional TR scheme may need to reflect the recent history of relevant issues within each region.

D. Energy Market Design

The Working Paper specifies a requirement for deregulated generation markets in which there are separate, bid-based auction markets for energy, regulation and operating reserves. Energy would have a day-ahead and real-time market. In the day-ahead market, multi-part bids (i.e., bids for start-up, no load and energy production) are required. The Working Paper specifies many features of these markets in detail. However, despite the length of the discussion, the treatment in this section, as in other parts of the Working Paper, is no more than a sketch. Despite the lack of detail, it is clear that a number of the aspects of the markets described are highly problematic. As background to the discussion below, we request that the Initial and Reply Comments of the New Mexico and Rhode Island Offices of Attorney General that were filed in FERC Docket No. EL01-118-000 (dated January 4, 2002 and February 5, 2002) be incorporated into this docket by reference. The comments below expand on many similar points made in the above referenced comments:

- Both theory and the actual experience in the existing ISOs have shown that for energy markets to operate properly they must be linked to installed capacity markets. To first approximation, energy markets should exist for the recovery of variable production costs, and capacity markets should recover fixed production costs. Unfortunately, the Working Paper does not even mention capacity markets, let alone discuss how they would be integrated with the required energy markets. However, the Options Paper does discuss capacity markets briefly. In the Working Paper, instead of being linked to an installed capacity market, capacity reserves are only treated as an "energy product" which responsible parties can either obtain directly, or pay for at a market-clearing price. In contrast, the installed costs of capacity reserves should be collected in capacity markets, though the operating costs of providing capacity reserves (namely operating reserves) could be linked to the energy market. If an energy market is competitive, and if it is structured as a single price auction, then even if all generators bid only their variable operating costs, most generations will collect a substantial margin above these costs. This margin should be credited to recovery of capacity-related and other fixed costs. A competitive capacity market would be one in which only those fixed costs required to produce a fair rate of return on equity above and beyond the margin collected in the energy market (and ancillary service markets) would be collected. This would imply that the prices for both energy and capacity were just and reasonable. (See the discussion in the New Mexico and Rhode Island AG comments in Docket No. EL01-118-000, dated January 4, 2002.)

- In the day-ahead energy market, the need to establish special options to handle bidding by resources, such as hydro or environmentally constrained thermal units, is correctly acknowledged. However, these special options are then required to be available to all generators, absent a showing that the use of the options will lead to market power, which may not be a good idea.

- Again, it is not clear what source of legal authority FERC is depending on to require all states and utilities to participate in the kinds of generation-related balancing markets discussed in section D. of the Working Paper, since FERC can not dictate what power purchases a utility should make to serve its retail load. While FERC claims that participation in the required bid-based balancing market would be voluntary as a means of obtaining generation services, this claim may not be functionally realistic if the prescribed energy balancing markets become the mandated energy balancing mechanism. FERC must ensure that participation in both the day-ahead and the real-time generation markets are truly voluntary. This must also apply to a bid-based capacity market if one is established, as well as the demand response market. However, the existence of the proposed types of energy markets is not voluntary, which itself may present FERC with serious jurisdictional problems. Furthermore, participation in the bid-based energy balancing market for pricing transmission services via FERC's proposed LMP pricing scheme is not voluntary, since FERC staff states on page 16 of the Working Paper that "nodal pricing must be used for both buyers and sellers in the day-ahead market." However, if participation in the day-ahead market is truly intended to be voluntary, and no one (or very few generation owners) participates, then how will congestion costs be accurately calculated? Analytically, congestion costs can only be computed accurately if <u>all</u>

generation units are bid into the day-ahead market (at variable costs), so this appears to be another serious internal inconsistency in the FERC proposed SMD.

- Only the second sentence of section D. claims to describe a problem with the current system for energy balancing, but the statement is so cryptic as to be incomprehensible. Again, it is FERC's obligation to extensively describe and document the claimed problems with the current system of balancing procedures before offering solutions to an undocumented problem.

- When the need for both a day-ahead and real-time energy market is discussed, FERC makes further claims that must be documented such as "experience has shown that the combination of a day-ahead and real-time market enhances system reliability and efficiency compared to operating only a real-time market." (Working Paper - page 12)

- The Working Paper does not consider the merits of continuing or developing a process for energy balancing and other ancillary services on a regulated cost-of-service basis, rather than on a bid-based market approach. This is a major issue that the FERC staff has continued to gloss over. Furthermore, whenever FERC uses the term "market" price or "bid-based" price recently, it seems to restrict its vision to a single price auction market structure, which itself needs to be justified. This is especially true since single price auction markets introduce a degree of market inefficiency into any system, as discussed above. Requiring the provision of energy balancing and ancillary service functions on a regulated cost-of-service basis may be much more attractive to many states and utilities, not the least because such an approach would eliminate the possibility of market power impacting the price of such services. Therefore, the prices would be just and reasonable. Such an alternative approach should be discussed at length by FERC, since this approach was very successful in several of the Northeastern power pools. This approach is still used internally by many large interstate utility holding companies. It provides a crucial cost baseline to which other schemes such as FERC's proposed SMD should be compared.

In general, the proposed SMD market rules enhance the likelihood that energy market bids will be above variable cost, rather than reduce this likelihood. This is an important issue because variable cost bids leading to variable cost-based dispatch is the mathematically known least-cost option for operating an electric generating system. Bidding rules that do not foster least-cost provision of electric service will not likely lead to just and reasonable rates as defined in and interpreted under the Federal Power Act, and they will not maximize economic efficiency. Nor do the project bidding rules support the basic reason why a market approach was adopted: to reduce costs and prices! We will return to this point in our general concluding comments.

E. Other Changes to Improve the Efficiency of Markets under SMD

This section of the Working Paper dramatically extends the role of RTOs beyond those functions included in Order No. 2000. The RTO would take charge of long-term planning for generation, transmission and DSR, decide what needs to be built, and issue RFPs for the construction of whatever it deems needed. Item 4 in this section describes the RTO's additional responsibilities. Quite remarkably, item 4 states that "the RTO would choose an ultimate solution..." (Working Paper, page 21) Item 2 limits the role of vertically-integrated utilities in planning. However, the Working Paper says nothing about the procedures or standards that an RTO would apply to conduct planning studies. For example, it does not explore least-cost planning, or integrated resource planning. Nor does it explain who would finance or own facilities constructed in response to the RTO's RFPs. Before handing such extensive, new responsibilities to the RTO, these issues need to be discussed with state governments, among other bodies. These proposals by FERC staff are all the more remarkable since the Federal Power Act does not give FERC any planning or siting authority over generation or transmission for either retail or wholesale load. Clearly, thus far, these powers have been reserved to the states.

Regional electric system planning is, of course, essential if the generation and transmission system is to operate most reliably and efficiently over the long term. However, assigning a planning decision-making function to the RTOs raises numerous issues. In many states, regulated utilities still have a responsibility to engage in integrated resource planning and least-cost resource procurement. The implementation of planning decisions, such as generating plant and power line construction, usually requires state-level permits, and other permissions by agencies such as the state public utilities commission. In light of the current primacy of state responsibility for planning and resource acquisition, particularly where utilities remain vertically integrated, a joint state/regional/federal partnership approach in place of that sketched in the Paper would be more appropriate for the future. However, if it were appropriate, state PUCs would have to relinquish some of their authority over planning. In this regard, it is important to note that FERC has never gotten involved in generation planning in the past, so to do so would be a real change in FERC's responsibilities and expertise. Federal legislation may be required to even allow for this change.

F. Market Monitoring and Mitigation

The Working Paper discusses and presents a long list of principles, mitigation measures and monitoring activities related to market power. The discussion suggests that FERC staff have a real interest in, and commitment to, addressing market power. However, in two crucial aspects, the approach taken in the Paper is inappropriate and inadequate, as the New Mexico and Rhode Island Office of the Attorney General have already pointed out to FERC in extensive Initial Comments and Reply Comments filed in FERC Docket No. EL01-118-000:

- The focus of the monitoring methods proposed by FERC staff is on the behavior of individual market participants, particularly economic or physical withholding. In addition, there needs to be a focus on the way the market behaves collectively, namely on "strategic bidding". Thus, FERC staff's definitions of economic and physical withholding are still too narrow – these definitions do not seem to have benefited from the comments of various parties in Docket No. EL01-118-000. In particular, there needs to be attention to the extent to which the prices in energy markets deviate from those that would be produced by a market in which bids reflected the short-run variable costs of production subject only to physical operational constraints.

- The principles proposed include the explicit acceptance of bidding based on "opportunity" costs. Yet, no attempt was made to reconcile this "principle" with both the need to ensure the economically efficient operation of the generation system, and with the bidding rules for a competitive capacity market. Nor was there any consideration of the effect that the acceptance of such opportunity cost bidding might have on attempts to analyze the behavior of market participants for market power. What constitutes a "real opportunity cost" is often hard to determine. It could become more difficult over time as those interested in exercising market power become more skilled in creating the appearance of such opportunities to cover the exercise of market power. But more fundamentally "opportunity cost"-based bidding might not be so problematic if the bids were, in fact, based on costs. But what FERC staff really mean here is that bids will be allowed which are based on opportunity "prices" not costs. But, if market power drives up prices in a neighboring system, there is no reason for FERC to allow that unlawful price to set the market clearing price in the energy market of the region under consideration. Similarly, allowing opportunity costs to determine bids for energy-limited resources would not be as problematic if all other bids were equal to, or close to, variable costs. However, if market power leads to bid prices well above variable costs, then the potential legitimacy of allowing opportunity cost-based bids which are really based on prices not costs is damaged.

The concept of "true scarcity" included in Principle 6 should be removed, since it is completely undefined. We suspect this term is simply being used as a cover-up for the exercise of market power. With competitive energy and capacity markets operative, energy bids never need to be made at above variable production costs in order for a fair rate of return to be generated.

- While cost-of-service based prices are appropriate for hours when a transmission constrained region becomes a strict load pocket, competition may still be very limited even when there is no single generating unit within the load pocket that is a must-run unit in other hours. Thus, the exercise of market power can be very substantial in a load pocket, even when some degree of competition is possible. Thus, price caps can not simply be lifted from load pockets as soon as demand within the load pocket falls sufficiently that no single owner's generating unit within the load pocket would be a must-run unit.

G. Long-Term Generation Adequacy

The Working Paper acknowledges that, in a market environment, the adequacy of generation capacity to ensure system reliability should be a continuing concern. However, beyond an expression of hope that enough new capacity will be built, there is little said in this section of the Working Paper. Fortunately, this issue received additional attention in the Options Paper. A SMD could address adequacy through the inclusion of a capacity market based on a required reserve margin that both requires that rights to physical generation resources be obtained by load-serving entities, and ensures that reasonable payments are made to those who make the required commitment to provide such resources. Thus, we support Option 2 in the Options Paper; namely, that a long-term installed capacity reserve margin be imposed on each load serving entity in a region to ensure that the wholesale power commitment of formal wholesale markets are met on a reliable basis.

However, again, there appears to be an important jurisdictional issue here, as for other generation-related issues. Currently, each NERC region handles system reliability issues somewhat differently on a voluntary basis, though the approach that NERC takes seems to work very well, on the whole. In addition, it has traditionally been the authority of each state PUC to ensure that the retail utilities under their jurisdiction have sufficient installed generation capacity to maintain adequate system reliability. FERC has not yet been given this authority by Congress. Thus, unless states and utilities voluntarily participate in a FERC-jurisdictional installed capacity market, FERC does not have the authority to mandate utility participation in such a market. This issue was also discussed above with respect to the RTOs' general responsibility for system planning under the proposed SMD.

H. State Participation in RTO Operations

As explained in the Working Paper, the SMD includes a currently unspecified "joint role" for state regulators, as well as an advisory role for other parties participating in RTOs. While it is important that the potential state role is recognized in the Working Paper, the way it is addressed is entirely inadequate. Unless the Congress gives FERC the authority to site electric generation and transmission facilities, the development of generation and transmission networks will require FERC, or institutions such as RTOs to which it delegates responsibility, to work in partnership with relevant state regulatory agencies which have the primary jurisdiction for siting. The effective regulation of vertically-integrated utilities within a market environment at the wholesale level will also require a joint partnership to ensure just and reasonable wholesale generation rates. The "joint and advisory roles" of the states need to be much better defined with the current legal limitations to FERC's jurisdiction in mind.

I. System Security

System security is a key issue. The extent to which responsibility for security is proposed to be centralized in an RTO, an institution which in many areas of the country does not exist as yet, is troubling. There are, for example, well-known abuses, such as investment "gold plating," which a utility might easily be enticed into by direction from an RTO, where the RTO would have no direct responsibility to those paying inflated utility charges. Some regulatory agency such as FERC must routinely perform prudence reviews of all RTO mandated charges prior to the recovery of such charges in wholesale transmission or generation rates.

J. Transitional Considerations

The Working Paper anticipates that initial activities related to the implementation of the SMD will include the implementation of physical trading hubs for which hourly locational marginal costs (really "prices") will be computed, and between which transmission service can be scheduled. As the Working Paper notes, this requires "institutional changes and software development." Here it is useful to recall that, in the *Economic Assessment of RTO Policy*, prepared recently for FERC by ICF, the cost of RTO start-up was put at only $1 billion to $6 billion nationwide. As regulators in the New England, New York, and PJM ISOs know, once start-up is complete, a major new bureaucracy is in place. A key issue is how fast this multi-billion dollar start-up, and the associated development of the RTO bureaucracy, can and will occur. Will there be time for the careful consideration of foundational efforts, particularly in areas that have not had the decades of experience that New England, New York, and PJM did in operating "tight" regional power pools? The proposed 60-day schedule to revise tariffs included in the Working Paper suggests that FERC is far too optimistic about the time that will be required for a realistic transitional period if they actually attempt to implement their SMD. Furthermore, how much additional cost and regulation will be required for these new "physical trading hubs" that are proposed? FERC staff do not present the results of any new analysis that they may have performed to indicate what the magnitude of these new costs and regulatory procedures may be.

General Concerns with the Working and Options Papers

The specific comments presented above point to the most general problem that we have with the types of generation and transmission markets discussed in the Working and Options Papers; namely, the proposed departure from the efficient tight power pool model in which there is an obligation to have sufficient physical reserves, and an assurance of least-cost dispatch based on variable costs subject only to physical constraints. While it may be difficult to see in the welter of detail, the Working Paper ignores this model completely, since it imposes bid-based energy (and, perhaps capacity) markets on all utilities, and on retail as well as wholesale customers. Again, we do not believe that FERC really means it when they say that participation in all the proposed generation markets will be voluntary. This disbelief stems from the fact that the proposed markets would not work properly if a sufficient number of utilities and other generation owners did not participate in each region. FERC's apparent departure from the more traditional tight power pool model, as a possible alternative to their SMD, means that, in principle, their proposed SMD will not provide electricity as reliably as possible, nor at the least reasonable cost. Developing deregulated markets of the sort that FERC is now proposing is not what was anticipated nor required under the Federal Power Act. The main legal question, that bears repeating over and over again, is whether generation and transmission prices that are not reasonably as low as possible can be found to be just and reasonable.

There is a very simple way for FERC to show whether it has even a minimal concern about the extent to which prices in the electricity markets required for the proposed SMD may raise costs to consumers if it is implemented. FERC could simply include a requirement in the SMD that RTOs require every bidder to submit, in confidence, its actual variable and fixed costs of production, and that the Market Monitoring Units required for each RTO compute all relevant Lerner Indices using these costs. Such indices provide a standard measure of the difference between the least-cost provision of power, and what might actually be achieved in the RTO's energy and capacity markets. FERC's failure to include this requirement in the final proposed SMD would send a very simple and clear message: FERC is basically unconcerned about the extent to which the transmission and generation markets created by the SMD minimize costs, and lead to just and reasonable wholesale, and, therefore, retail prices.

Conclusion

We oppose the proposal of FERC staff that a SMD be established and required for all retail, as well as wholesale, transmitters of electricity. This should be a decision left up to the states, as we believe federal law dictates. This is especially true for the role that new generation-related market structures should play as providers of electricity for each utility. Furthermore, we strongly request that FERC document its claims that there are such significant problems with the current OATT, which it only recently implemented, such that the electric industry, and electric transmission generally, needs to be completely revamped yet again. Without the clear documentation of specific problems, we find that the current OATT is quite satisfactory in its general structure, and does not need to be changed as long as congestion costs are fairly charged to each set of native load customers. However, market clearing "prices" should not be substituted for congestion "costs" as a fair means of pricing congestion.

Finally, given the many challenging jurisdictional issues that the Working Paper and the Option Paper raise, FERC should attempt to resolve those legal issues first with state policy makers prior to requiring the restructuring of retail utility service.

Respectfully Submitted,

SHELDON WHITEHOUSE,
IN HIS CAPACITY AS ATTORNEY
GENERAL OF RHODE ISLAND

RHODE ISLAND DIVISION OF
PUBLIC UTILITIES AND CARRIERS

By their Attorney,

/s/

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Attorney for the Colorado Office of
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DATED: May 3, 2002

CERTIFICATE OF SERVICE

I hereby certify that I have this day filed the foregoing documents at the Federal Energy Regulatory Commission by electronic filing and served a copy upon each person designated on the official service list compiled by the Secretary in this proceeding.

I further certify that the paper copies mailed to the parties on the official service list contain the same information as contained in the electronic media filing, that I know the contents of the electronic media and the paper copies and that the contents as stated in the copies and on the electronic media are true to the best of my knowledge and belief.

Dated at Providence, RI, this 3rd day of May, 2002.

/s/

Paul Roberti
Assistant Attorney General
Chief, Regulatory Unit
Rhode Island Department of Attorney General
150 South Main Street
Providence, RI 02903

January 4, 2002

Hon. David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: **AEP Power Marketing, Inc., AEP Service Corp., CSW Power Marketing, Inc., CSW Energy Services, Inc., and Central and South West Services, Inc., Docket Nos. ER96-2495-015, ER97-4143-003, ER97-1238-010, ER98-2075-009, ER98-542-005 (Not Consolidated)**

Entergy Services, Inc., Docket No. ER91-569-009

Southern Company Energy Marketing L.P., Docket No. ER97-4166-008

Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, Docket No. EL01-118-000

Dear Secretary Boergers:

Attached for filing via the FERC's Electronic Filing Program is an electronic file containing this transmittal letter, the "Comments of the New Mexico and Rhode Island Offices of Attorney General and the Rhode Island Division of Public Utilities and Carriers," and the "Certificate of Service" for the same in the above-referenced proceedings.

Thank you for your assistance.

Sincerely,

/s/

Deborah R. Tope
Paralegal
New Mexico Attorney General's Office

cc: Service List

Enclosures

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Investigation of Terms and Conditions Of Public Utility Market-Based Rate Authorizations	))))	**Docket No. EL01-118-000**
AEP Power Marketing, Inc., et al.	)	**Docket Nos. ER96-2495-015, et al.**
Entergy Services, Inc.	))	**Docket No. ER91-569-000**
Southern Company Energy Marketing, L.P.	))	**Docket No. ER97-4166-000**

COMMENTS OF THE
NEW MEXICO AND RHODE ISLAND OFFICES OF ATTORNEY GENERAL
AND THE RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

Patricia A. Madrid, in her capacity as Attorney General of the State of New Mexico ("New Mexico"); Sheldon Whitehouse, in his capacity as Attorney General of the State of Rhode Island and the Rhode Island Division of Public Utilities and Carriers (collectively, "Rhode Island")[1]; jointly submit this filing pursuant to the Commission's authorization for filing comments in response to its Order Establishing Refund Effective Date and Proposing to Revise Market-Based Rate Tariffs and Authorizations in Docket No. EL01-118-000, and in response to the Commission's concurrent Order on Triennial Market Power Updates and Announcing New, Interim Generation Market Power Screen and Mitigation Policy in several Dockets, including ER96-2495-015, both issued on November 20, 2001.

[1] Rhode Island filed a Motion to Intervene in Docket EL01-118-000 on November 30, 2001, and a Motion to Intervene out-of-time in the pending AEP and related proceedings on December 7, 2001. New Mexico has filed its Motion to Intervene in Docket EL01-118-000 simultaneously with the filing of these comments.

1. SUMMARY OF THE ORDERS AS PERTAINS TO OUR COMMENTS

In its Order Establishing Refund Effective Date and Proposing to Revise Market-Based Rate Tariffs and Authorizations (hereafter the 'Tariffs Order'), the Federal Energy Regulatory Commission (hereafter 'FERC' or the 'Commission') recognizes and acts on its responsibility under Section 206 of the Federal Power Act to maintain just and reasonable prices in wholesale power markets. The Order states: "We have a responsibility under the FPA to monitor wholesale markets to ensure that jurisdictional rates in the markets remain within a zone of reasonableness." (Tariffs Order, 5.) As a remedy to anticompetitive market behavior and the exercise of market power, the Order proposes that a seller's market-based rate authority be conditioned upon the absence of market power and a prohibition against anti-competitive behavior, and be "subject to refunds or other remedies as may be appropriate to address any anticompetitive behavior or exercise of market power." (Tariffs Order, 5.)

In its Order on Triennial Market Power Updates and Announcing New, Interim Generation Market Power Screen and Mitigation Policy (hereafter the 'Market Power Order'), the Commission replaces the hub-and-spoke methodology for market power screening on an interim basis with a Supply Margin Assessment (SMA) screen. The Commission had previously "looked to a benchmark for generation market power of whether a seller had a market share of 20 percent or less in each of the markets." (Market Power Order, 7.) Under the interim SMA screen, a threshold for generation market power concerns will be "whether at least some of the applicant's capacity must be used to meet the market's peak demand" or, in other words "if its capacity exceeds the market's surplus of capacity above peak demand" (i.e., supply margin). Mitigation is achieved through the required offering of uncommitted capacity to the market at cost-based rates, and by splitting the savings between supplier and buyer "which was the traditional cost-based ratemaking model." (Market Power Order, 12.) To accomplish this, the Order requires the supplier to post projected hourly variable-cost data each day for all energy offered for spot market sales. For mitigating market share that exceeds the Supply Margin, the Order requires that potential supply interconnections will be evaluated as a competing network resource without having to formally designate a particular load or having to be selected as a designated network resource. In addition, a requirement that applicants post on their websites optimum locations for new generation facilities will "facilitate least cost integrated planning." (Market Power Order, 14.)

New Mexico and Rhode Island submit these comments to FERC in both of the above captioned sets of dockets. We hope that these dockets represent the beginning of a new attempt by FERC to ensure that all wholesale electricity markets within the US maintain just and reasonable rates under Section 206 of the Federal Power Act. It is very important, in our view, that FERC adopt consistent policies throughout the nation to accomplish this end. For example, we urge FERC to establish effective market monitoring and mitigation policies for <u>all</u> types of wholesale power markets, whether they are ISO-run day-ahead spot markets with bilateral contract markets on the side as in New England, or just bilateral contract markets, as currently exist in the desert Southwest. To us, effective market monitoring and mitigation necessarily implies that wholesale electric rates should be, on average, no higher than cost-of-service based rates for the types of products involved would have been <u>if these power markets had never been deregulated</u>. If FERC does not rely on cost-based rates as a price ceiling, then how can deregulation ever be clearly demonstrated to have been of value to electric consumers? In fact, we believe that some of the very court precedents that FERC cites in its June 19, 2001 Western Order are clear that cost-based wholesale rates provide the only reasonable basis for determining the proper "zone of reasonableness" into which all actual wholesale prices must fall. In our opinion, one can not have a zone of reasonableness without knowing precisely what specific prices that zone centers on, and without knowing how big the zone of reasonableness can be. In general, prices below cost-based rates would clearly fall into a zone of reasonableness as long as they were not confiscatory relative to the legitimate interests of generation owners. However, it is not clear that there would be any valid rationale, given today's electricity markets, for wholesale electric rates to be higher than cost-based rates. Clearly, if there is any such rationale, FERC will have to clearly describe such a rationale, which it has never done in previous orders.

Thus, in submitting these comments we applaud the general objectives that FERC has cited in each of these two orders that we will discuss from November 20. Similarly, we agree with the language of the proposed tariff amendment from page 4 of the Tariffs Order, and we agree with the proposed Refund Effective Date. However, we still find that many of the specific issues related to market power addressed in these Orders are not addressed consistently, logically, and effectively. For example, we still do not find that FERC has defined the mechanisms for being able to sufficiently identify when market power has been exercised by generation owners, which marks a fundamental disappointment with these orders. This is because we do not believe that FERC has yet developed a coherent theory of how market power is exercised, and, therefore, how it can be cured. Thus, most of our comments below are provided with the intention of helping FERC understand what, in our view, must be the starting point for a better approach to both implementing that proposed tariff amendment, and to monitoring and mitigating market power for utilities like AEP, the Southern Company, and Entergy. Since the tariff language is so general, the real value of such an amendment comes almost solely from how the language is implemented in US wholesale power markets. If it turns out, as some have already claimed, that the proper implementation of comprehensive market power monitoring and mitigation schemes is too "intrusive" into market operations, and will make the operation of the resulting markets too mechanical and over-determined for pro-market advocates, then it may be the case that it will prove to be far better to simply return to cost-of-service based ratemaking for wholesale electric markets, just as many states have continued with, and are returning to, traditional regulation at the retail level. Thus, if it turns out to be the case that our only choice is between wholesale electric markets that are permanently and inevitably riddled with market power, and traditional cost-of-service based regulation of wholesale market prices, which used to work quite well, then traditional regulation will be our only legal course of action under the Federal Power Act.

2. A CONCEPTUAL FRAMEWORK FOR REVIEWING THE NOVEMBER 20, 2001 ORDERS

a. We believe that in these orders, and in others preceding them, the Commission's approach to its objectives fails in fundamental ways. The core of its failure is to avoid the critical question of exactly what constitutes just and reasonable rates.

The immediate objective in these Orders is to define how market power can be exercised, and to set an interim mechanism in place that mitigates and prevents market power in certain wholesale markets. However, the ultimate objective is to "ensure" just and reasonable rates in all wholesale power markets, as is described in the text of the Orders. Unfortunately, these Orders proceed to formulate a market power test that is merely *structural,* without any *behavioral* performance parameters attached to it. Therefore, the Commission seems willing to accept on *faith* that electric power markets will produce just and reasonable rates as long as high-level structural screens are put into place. Thus, it is FERC's lack of willingness to define in concrete terms what would define a just and reasonable rate, and its continued propensity to assume that the market will deliver such rates with only limited structural screens in place, which is at the heart of our skepticism regarding the approach to actually achieving just and reasonable rates as proposed in these Orders.

As noted above, the subject of these Orders is really much broader than simply how to define and control market power. The Orders rightfully frame the whole discussion of market power in the context of FERC's obligation to ensure just and reasonable rates, but the proper conceptual, evidentiary, and quantitative connections between market power, market-based rates, zones of reasonableness, and just and reasonable rates are still missing. FERC still has not followed the necessary procedures that it described for itself on page 26 of its June 19 Western Order for when it adopts market-based rates. "The Commission must: (1) provide a clear and reasoned analysis of the need for market-based pricing to promote the statutory objectives of the FPA; (2) support its decision with substantial evidence; and (3) assure that the resultant market-based rate falls within a 'zone of reasonableness'." Thus, even if FERC believes that it has done #1 above, though we do not believe that it has, it certainly has never even attempted to do #2 or #3 for either the New Mexico region, for the New England markets, or for <u>any</u> US wholesale electric market. If FERC believes that they have carried out #2 and #3 above for these regions, we request that FERC list the specific Orders and page references which contain those analyses in its response to these comments.

We propose to frame the detailed discussion responding to the two new November 20 Orders that appears in Section 3 below through our responses to three basic questions. This will help provide what we believe is the proper theoretical framework for analyzing the two Orders:

1. How far above cost of service can rates be before they become unjust and unreasonable, i.e., how should the zone of reasonableness be determined for either individual generating units, or for portfolios of units?

2. Are market-based rates, in the absence of market power, always just and reasonable rates? Does perfectly competitive long-run marginal cost-based pricing in an electricity market result in just and reasonable rates even when the resulting prices are significantly higher than cost-of-service rates?

3. How should FERC define the mechanisms for exercising market power and for controlling market power? A critical element of this discussion is how should market structure be taken into account when establishing methodologies to monitor and mitigate market power? What kind of market structure is most likely to lead to just and reasonable rates, if any can? (The interaction between capacity and energy markets is particularly important in this regard.)

b. How far above cost of service can rates be before they become unjust and unreasonable?

The Commission's objective in these Orders, and its statutory mandate, is to "ensure" just and reasonable rates. However, the Commission has never defined such rates in relation to cost-based rates. Without a notion of what the result should look like, we believe that FERC cannot truly know if it is likely to reach its objective.

One would presume that defining the objective before embarking on a project would not be an outlandish notion. Nonetheless, the Commission has repeatedly failed in this regard in the context of its discussion of market-based rates and market power mitigation. Prior to these two November 20 Orders, the best example may be the Order of June 19, 2001, on market power mitigation in the Western States (hereafter the 'Western Order'). In that Order, the Commission acknowledged that when authorizing market-based rates, it must still "assure that the resultant market-based rate falls within a 'zone of reasonableness', even if market power is completely absent."[2] Such ambiguous terminology, derived from a previous court finding, allowed FERC to speak of its obligation under Section 206 of the Federal Power Act without actually acknowledging in any concrete terms what that obligation would constitute. The Commission

[2] Order on Rehearing of Monitoring and Mitigation Plan for the California Wholesale Electric Markets, Establishing West-Wide Mitigation, and Establishing Settlement Conference, (June 19, 2001), 26.

never referred to any other studies, analyses, or previous Orders that described and implemented a methodology for determining such a zone of reasonableness, except in reference to the court's finding that the court could not "invalidate rate orders that fall within a 'zone of reasonableness,' where rates are neither 'less than compensatory' nor 'excessive.'[3] This language used by the Court certainly sounds like a result obtained by setting a fair ROE in the process of traditional cost-of-service ratemaking.

FERC needs to understand that using traditional cost-of-service methodologies for setting rates helps to illustrate how small a zone of reasonableness might be, at least if it were to move upward from traditional cost-based rates. For example, a five percentage point spread in the return on equity (ROE) allowed to a generation owner, from 10-15 percent per year, might only change the underlying cost-based rates by 2 percent. This implies that even if FERC wanted to allow market-based rates to compensate generation owners at a very generous level of a 15 percent ROE, it could only allow market-based rates to average 2 percent above a more traditional ROE based cost-of-service level. This is a rigorous standard, and FERC has certainly not provided the public with any numerical analyses of which we are aware to show that deregulated wholesale market-based rates in the southwest or New England have routinely averaged within 2 percent (or any similar number) of what traditional cost-based rates would have been.

One related question, then, that was left unanswered in its June 19, 2001 Order, and that remains unanswered, is how high can rates be, above a level that is merely compensatory to generation owners, before they become "excessive"? The Commission did not emphasize the

[3] See footnote 52 in the June 19 Order: Farmers Union Central Exchange, Inc. v. FERC, 734 F.2d 1486 (D.C. Cir. 1984), cert. denied sub nom. Williams Pipe Line Company v. Farmers Union Central Exchange, Inc., 469 U.S. 1034 (1984)

fact that the Court concluded in the same case noted above that "without empirical **proof** that competition will ensure that actual prices are just and reasonable, a regulatory scheme may not rely on prices established through bilateral negotiations or other market-based means as satisfying its [FERC's] statutory obligations." (Emphasis added.)[4] If FERC does not agree with the reasoning behind our example above, it should state why not, and should also state what methodology FERC will rely on to determine a zone of reasonableness. This language of the Court would also appear to require FERC to <u>directly</u> monitor and mitigate prices in the long-term bilateral markets, which it has refused to do.

Providing such proof that competitive electricity markets will ensure just and reasonable rates would require the Commission to do two things. First, it would have to actually define just and reasonable rates to know when they were achieved. Secondly, it would then have to analyze different market structures, both empirical data from existing markets as well as the predicted outcomes of alternative market structures, and determine whether the rates generated by these market structures meet the requirements of what constitutes just and reasonable rates by the Commission's own definition. Unfortunately, the Commission chose not to produce such proof in its Western Order, and it has not stated how this would be done now for the entire US in order to implement the Tariffs Order language. Instead, the Western Order only cited court decisions in defense of FERC's decision to implement price caps as market power mitigation, noting that the Commission "has never bound itself to a rule requiring either rigid regulation or textbook markets." The conclusion was that "nothing requires the Commission to revert to a cost-of-service ratemaking approach whenever it finds flaws in the market structure." (Western Order, 26) This was the Commission's conclusion even though actual cost of service is the only reasonable default for determining the upper limit for whether competitive market prices are just

[4] Op. cit. 2.

and reasonable. The obvious implication was that, on June 19, FERC was willing to accept less than competitive "textbook markets" as long as prices did not exceed a certain capped level regardless of what the average embedded cost of production might be. Again, the Commission never defined in the June 19 Order how far above the average cost of service the mitigated rates could be before concern about excessive market power might legitimately arise. The Commission merely assumed that the price caps it set would lead to average rates being just and reasonable.

Specifically, by setting a price cap for the Western markets that reflected a competitive energy market price set during a single hour, FERC appears to have assumed that doing so would lead to just and reasonable rates for all other hours of the year, in all affected wholesale markets. Yet, clearly, that is a huge leap of faith. Thus, even if there was no remaining market power in that single hour, every other hour might have been impacted by large amounts of market power. For example, a $92 per MWH price cap as derived from incremental variable costs in a Stage 1 deficiency hour, would clearly not constitute a just and reasonable rate in hours in which a competitive energy market price based on the same measure of incremental variable cost was only $30 per MWH. And all prices between the two would also not be just and reasonable, based on similar logic. (Ignore other markets except the energy market for a moment.)

We realize that the Commission's reticence to define its objective in sufficient detail may be born out of apprehension of the consequences of doing so. Once the right question is asked, i.e., what truly is a just and reasonable price, the result may be that FERC has to defend deregulated wholesale markets from an impossible position in face of the fact that cost of service would be the only definitive test of competitive prices, and the actual basis for just and reasonable rates. As long as FERC does not ask the dreaded question, it does not have to face the answer and defend its position with respect to certain (or all) wholesale market structures that may be incapable of producing just and reasonable rates.

c. Does perfectly competitive long-run marginal cost pricing result in just and reasonable rates even when the resulting rates are substantially higher than cost-of-service rates?

First, in the June 19 Western Order discussed above, the Commission defended its use of short-run marginal cost pricing as a useful point of reference in competitive markets. Yet, it remains ambiguous whether marginal cost pricing, particularly as represented by strict short-run marginal cost bidding into energy markets (variable cost pricing), is what FERC would consider to be the definitive test of competitive markets and, thus, the bidding strategy that would presumably lead to just and reasonable rates. Or would FERC stress the need to use long-run marginal costs (including fixed costs) to define a competitive market price, as would be more appropriate? Again, one of the mitigation methods imposed by the Commission in that Order was the imposition of variable-cost bids. Yet, if strict variable-cost bidding behavior is the test that FERC would look for in determining whether electricity markets are competitive, as opposed to using it only as a mitigation tool after much looser structural screens have identified market power by any number of market participants, one must ask whether strict short-run marginal cost pricing always (or ever) leads to just and reasonable rates.

Second, what FERC seems never to have acknowledged is that it is entirely possible that in a given market, rates based on cost of service (i.e., the average embedded costs of the resource base) could be significantly lower than the competitive marginal cost, market-based rate in the same market. This could be true even if higher long-run marginal costs rather than short-run marginal costs were used as the basis for deriving the market-based rates. For example, a study prepared by Stone & Webster Management Consultants for the Colorado Electric Advisory Panel in May 1999 found that, projected into the future, market rates based on full long-run marginal costs in Colorado (and most of the West) would be significantly higher than cost-of-service rates. This was true even though the market rates yielded a full 15 percent ROE to generation owners. The primary reason for this is the low average embedded cost of generation resources serving Colorado (and most of the West) today. Without a sudden and significant drop in long-run marginal costs (an unlikely occurrence), this condition would prevail for a long time – perhaps forever. In such an instance, would FERC insist that marginal-cost based rates were still just and reasonable because they resulted from a competitive market, even if they were substantially higher than cost-of-service based rates? Assuming that the Colorado study was correct, it appears that in the long run, market-based rates in the West will be inherently unjust and unreasonable for precisely this reason.

d. How should FERC define and control market power?

As we discuss the issue of controlling market power, we need to keep in mind that even when the Commission is confident that market power does not currently exist in any given market, there is no assurance that the market will produce just and reasonable rates. Just how far we are from such assurance depends on how we define market power, and how long-run marginal costs compare to cost-based rates. FERC now acknowledges that its traditional very loose approach to controlling market power that relied on structural screens, as opposed to behavioral parameters, and that set a threshold for market power concerns at very large market shares such as 20 percent, will yield no assurance at all that the market is producing rates that are just and reasonable. Conversely, a definition of market power that is more aggressive, and that leans more on behavioral parameters rather than broad structural conditions, is likely to give greater relative assurance that rates may approach just and reasonable levels. After all, market power is a behavioral phenomenon; it is the outcome of certain complex behaviors that may be enhanced or suppressed depending on the details of the market structure and the market rules.

We agree, then, with the Commission's conclusion in the current Orders that the hub-and-spoke methodology, and its market-share threshold for market power concerns, is not adequate. Similarly, the Commission's past reliance on the HHI index was also never sufficiently justified, and had similar substantial flaws, since it was also a purely structural index. Thus, it is clear that new methodologies for detecting the potential for market power are needed, whether for merger applications, or for market-based rate applications. Aside from the need to incorporate transmission constraints into such market power screens, a more robust test of market power cannot simply rely on an arbitrary market share for any single market participant, which in the past had been 20 percent, or so. (The 1800 point HHI level that FERC used as a screen was equivalent to equal market shares of about 5.5 firms, which was an 18 percent market share for each.) Unfortunately, in these new Orders of November 20, FERC only starts to address the flaws of the existing market monitoring methodologies that it has relied on in the past by introducing the Supply Margin Assessment (SMA) methodology. However, this change does not address the fundamental problem with FERC's past approaches, which is the exclusive use of structural screens to detect market power. Structural screens that look at relative market share are always arbitrary in nature, do not take market structure and rules into account, and are not based on any precise determination of how much and under what precise conditions market power is likely to exist. Unfortunately, the proposed SMA screen is also purely structural.

We will describe in greater detail below where the major problem with FERC's new proposed approach lies, and what a better market power screen would look like, but the essence of such a screen would consist of behavioral thresholds for market power mitigation. It needs to be understood that market power is a condition, or a consequence of the structure of the market, that allows certain behaviors to exist. A market participant who is in a position to manipulate the market price does not have to act on this ability and actually exercise his market power. Therefore, a purist's perspective might be that the potential for exercising market power could be detected by structural screens, while only the actual exercise of market power should be targeted with behavioral remedies, such as imposing variable cost bidding.

We believe that this would not be correct. One reason is that a simple structural screen will not be able to take into account all conditions which lead to market power, especially when it is set at an arbitrary level of market share, which is a problem that even the new SMA screen has not overcome. The "bottom line" for measuring market power impacts is to measure actual prices in comparison to what competitive prices would be. There is no way around the need to do this. Second, if the structural screen were set too low, it could target too many market participants who may, in fact, not have been able to exercise market power. Third, structural screens target all market participants that may be able to exercise market power, whether they can act on that ability or not. This last point may be a minor concern, but the solution for all is the same, which is the use of behavioral tests. If the Commission were to set a performance standard such as limiting energy market bids to a range that is close to the variable operating cost of each generating unit, all attempts to exercise market power would be able to be detected and mitigated simultaneously, without fail.

The difference between a structural screen like the SMA, and a behavioral one, can be described as follows: A structural screen looks for the "usual suspects" and rounds them up to preempt a possible offense, with the hope that the remaining population behaves within the law. A behavioral screen goes farther and actually monitors the entire population continuously once the market has been structured properly, thereby preventing any offense. This second approach, which is a solution to the failures of previous market power screens, may be simple and even obvious. Yet, we realize the "ideological" resistance that is present in some circles against accepting such methods that call for cost-based monitoring and mitigation tests. However, such resistance is unfortunate because it appears to derive from the ideological tendency to support "market autonomy" above all, rather than any implications of a particular market structure for the health of the markets, or for the reasonableness of the rates that would result. Or, this resistance may instead derive from a lack of consideration of how alternative market structures would help solve market power problems.

e. A reasonable market structure is a critical element for ensuring the possibility of competitive markets, where separate capacity and energy markets are a key to success.

Having recognized that behavioral screens based explicitly on price must be used to fully control market abuses, we must identify which types of tools are useful to accomplish comprehensive market monitoring and mitigation. The single most important element in detecting the exercise of market power is the ability to identify the true marginal cost of each market resource, including potential market entrants, at each moment in time. If the market monitors know the incremental fixed and variable costs of each existing or potential new power producer, market power mitigation becomes the relatively simple task of curtailing bids and prices to fairly closely match incremental costs, on average. For example, if the Commission had determined that resource bids into an energy market that were more than five percent above the variable operating cost of each generating unit were uncompetitive, then any bid that was placed above this level could be immediately adjusted downward. The market monitor, presumably the system operator, could keep daily logs of the marginal variable costs for each resource. When a bid was placed that strayed from this cost baseline, the monitoring authority could replace the bid with a default variable cost-based bid.

A similar procedure could be followed in an installed capacity market, and it would be relatively straightforward if the market were only operated once per year, based on the need for capacity to cover the annual peak load plus an adequate reserve margin. Here the focus would be on whether the ROE earned by the generation owner on that asset, or on its entire portfolio of generation assets was reasonable, once all sources of revenues for that unit were taken into account including all infra-marginal revenues recovered from the energy or ancillary services markets. (This could be done based on prior year revenues from those markets, or some other approach.) The benefit of this type of monitoring and mitigation scheme goes beyond its comprehensive nature and effectiveness to mitigate anti-competitive bids. The immediacy and inevitability of such mitigation would actually be such that any attempt at exercising potential market power would be preempted by the system operator, making the *attempt* at exercising market power relatively futile. In other words, market power monitoring and mitigation might become a single integrated function so that market prices would rarely have to be corrected, and so that refunds would almost never be required. In fact, refunds could be determined in the course of adjusting capacity prices in the installed capacity market, perhaps only once per year. However, while the type of scheme outlined above might work for formal spot markets, other types of monitoring and mitigation schemes would have to be developed for bilateral markets, especially non-spot bilateral markets.

Note that FERC seems to always gloss over the need for ensuring that longer-term prices in bilateral markets are also just and reasonable under the Federal Power Act. It is certainly not obvious that long-term bilateral contract prices will always be disciplined to just and reasonable levels based on the option that buyers could simply rely on future spot markets if they do not sign longer-term bilateral contracts, especially if formal spot markets do not exist as is currently the case in most of the US. In addition, spot market prices might temporarily be too high to be indicative of what average wholesale rates should be, especially if those markets are very thin, as they may be for new RTOs, especially if spot markets are really limited to being energy balancing markets. Finally, there is the possibility that spot market prices, even if competitive, might be above a zone of reasonableness with respect to cost-based rates, as discussed above. In that case, by definition, the establishment of spot markets can not possibly help bilateral contract prices be just and reasonable. These are difficult issues which FERC needs to address at much greater length than they have in the past when considering the need to monitor and mitigate bilateral contract markets. In fact, in its December 19, 2001 Order on the Western markets, FERC has gone the wrong way on this issue by confirming on rehearing its decision not to impose price caps on any other Western bilateral contract sub-market other than contracts for 24 hours or less. (Order on Clarification and Rehearing, December 19, 2001, p. 151.)

If the general approach to monitoring and mitigating spot markets that we presented above were workable, at least two conditions would have to be met. The requirement to report incremental fixed and variable costs would have to be imposed on all generating units and generation owners, and the reported incremental cost of each resource would have to be verifiable. Pure traders, as opposed to generators of power, could be required to be price takers in spot markets by bidding zero, as FERC has recently ordered in its new December 19, 2001 Order on the Western markets, though this requires further thought. (See page 47.) Thus, the costs of purchase to traders would not have to be revealed if this approach were taken. Naturally, the market monitor would have to be vested with the authority to mitigate bids to a level reasonably close to reported incremental cost. Perhaps a maximum increase of 5 percent in the energy market would be reasonable in order to get the price signals to be reasonably accurate, as long as the actual infra-marginal revenues were accounted for in setting reasonable limits for bids into the annual installed capacity market so that total wholesale prices would not be too high by 5 percent.

The first condition is necessary to apply to all generators because, as discussed above, limiting the reporting requirement to those market participants that fail any particular structural screen may not detect all, or even most, actual market abuses. We must remember that the Commission has not offered any proof that only "pivotal" market participants as defined by the SMA screen can exercise economic or capacity withholding, or strategic bidding (which FERC ignored). The second requirement, verifiability, is obviously necessary because the market monitor needs to be able to confirm, with a fair amount of certainty, that reported costs are not inflated. Penalties for false reporting will probably be needed. In addition, we support FERC's previous rulings that opportunity costs, scarcity rents, etc. will not be included in any definition of incremental costs used for the purposes of market monitoring or mitigation. This should also pertain to hydro-electric power, and similar zero incremental cost generation options. The reason for this is that the lowest-cost way for society to dispatch hydro that can be stored is to dispatch it in a manner to lower net peak demands and the high actual variable costs needed to meet those peak demands. If the bids into the energy market are limited to direct incremental costs, the opportunity costs for storage hydro become equal to future avoidable direct costs. But if the bids of hydro resources into an energy market are not restricted in this way, then the system operator should dispatch hydro based on when the operator computes that overall system prices can best be minimized.

In the November 20 Market Power Order, the Commission has also taken an important step toward incorporating incremental-cost reporting for a monitoring and mitigation scheme, though they have neglected the need to report annual <u>fixed costs</u> including the fixed carrying costs of capital investments, for use in monitoring and mitigating <u>capacity markets</u>. Another problem is that in the Market Power Order such reporting is only required of those who have failed a structural market power screen; namely, the Supply Margin Assessment. Another problem is that the Order does not acknowledge the need for having the reported incremental or annual costs be transparent and verifiable to FERC. We believe that such cost transparency can be accomplished fairly easily. In addition, the reporting requirement must also be applied to all generators selling into RTOs/ISOs as part of their market power monitoring and mitigation schemes. Of course, the reality of being able to keep up with the potential workload related to market power issues is that FERC might best just start over by revoking market-based ratemaking authority for all transactions not made in the context of an RTO/ISO, unless FERC puts into place some other set of institutional structures designed to allow for routine monitoring and mitigation of all the other types of power markets throughout the U.S.

f. The prime rationale for identifying the separate fixed and variable marginal costs of each market resource for an effective market monitoring and mitigation scheme in wholesale power markets is the separation of capacity and energy markets.

As the discussion of market monitoring and mitigation above indicates, in the absence of an installed capacity market, resource bids into the energy market over the course of a year must, on average, reflect the equivalent of the full revenue requirement of the unit in order that the owner can make a reasonable profit on the investment. Thus, if there were only an energy market, it would be very difficult for FERC to be able to determine if such bids were truly competitive. FERC would be required to establish individual cost-of-service rates on an average basis by forecasting a likely capacity factor for each generating unit. Of course, it is quite unrealistic for FERC or an RTO/ISO to be able to accurately forecast such an annual capacity factor prior to being able to determine if any given energy market bid for each generator is reasonable so that the fixed costs per operating hour in addition to variable operating costs are known. Yet, this is the only way in which the Commission or the RTO/ISO could know whether a particular bid were even approximately competitive or not, and that judgment would still depend on what the actual bids from the unit would be for the remainder of the year. (We assume that no one would bid the exact same price in each hour.) The fact that this would be a cumbersome and inaccurate process may have led the Commission to believe that it would be impractical as an effective means to control abuse of market power when it considered establishing price caps in the June 19 Western Order. The Commission argued on page 34 of that Order that the explicit recovery of fixed costs was not necessary. The Commission argued that "by using the marginal cost of the last unit dispatched to establish the market clearing price during periods of reserve deficiency, the Commission is permitting all more efficient generators a fair opportunity to recover capital costs." The Commission also dismissed concerns of the generation owners that the last unit dispatched would not be able to recover any of its capital costs by stating that "the amounts earned on the more efficient plants will cover the investment in the marginal plant." (Western Order, 34.)

We believe that this argument of FERC's is quite confused. But even if it were correct, the Commission has not shown that their argument is likely to be correct numerically, for any likely system of generators. Thus, here we support the concern of the generators that the Commission's approach to setting price caps might under-collect fixed costs, including a fair return on investment. Of course, the recovery of fixed costs could easily go the other way too, which the generators do not mention. Given the fact that the same price cap would apply in all hours of the year, bids that would fall below the price cap but which would be far above a competitive energy market clearing price in other hours of the year might lead to higher revenues being collected over the course of a year than required for full annual fixed cost recovery.

Amazingly, in this Order FERC does not discuss alternative market structures that it could have established in California that would be much closer in form to the market structures that it had already established in the Northeast, namely a structure which includes an installed capacity market. This would have allowed FERC to solve the difficulty with the potential for over- or under-collection of fixed costs given the way FERC set price caps for the West. Of course, FERC could still do this since the conceptual and regulatory problem continues to this day. This same potential problem also applies to FERC's approach to price mitigation if an applicant for market-based rates fails the SMA test. There FERC also relied strictly on variable costs, and did not propose a means for checking the adequacy of capital cost recovery.

The big advantage, then, of the alternative market structure that we have suggested is that having a separate annual installed capacity market removes the final consideration of fixed-cost recovery out of the realm of the energy market. As long as a functional capacity market is in place, the Commission can be assured that a variable-cost bid in an energy market, or a bid that is reasonably close to the incremental variable cost of the generating unit, is both a competitive bid and a fair bid, since any additional fixed cost recovery required will be allowed in the installed capacity market.

However, this alternative market structure that allows for such an effective check on potential market power abuses will certainly evoke the image of cost-based rate regulation in many people's minds, and, to some, that may be sufficient reason enough to denounce it because the "principle" of "market autonomy" is being challenged. While this market structure does allow both the energy and installed capacity market to set their own prices over various time periods, assuring some degree of continued market autonomy, the market prices would not be allowed to stray far from annual average cost-of-service based rates before mitigation would be imposed. However, if thresholds for market power concerns and mitigation are truly based on cost of service, it is difficult to argue against such methods. As discussed previously, how could one attest that average prices significantly above cost of service could result in just and reasonable rates? Note also that "market autonomy" would still exist on an hour-by-hour basis in the spot energy market. Prices in the energy market would still vary by time of day and season, thus giving power purchasers better price signals than existed in the past under bundled rates. Another alternative to the above approach to market mitigation for each individual generating unit, would be to allow bids into the annual installed capacity market that would only be capped for the generation owner's entire portfolio of generation options, and not for a single generation unit. In fact, FERC has offered generation owners a somewhat similar portfolio-based approach to wholesale rate regulation in recent orders, including the Western Order, if these owners do not believe that they will be able to successfully recover all their fixed costs on an annual basis given the manner in which FERC has developed price caps for the Western markets. (Western Order, 24.)

g. The only regulatory option that FERC has for monitoring and mitigating market-based rates is to use cost-of-service as the baseline.

In its June 19 Western Order, the Commission found that a return to cost-of-service ratemaking in the Western markets would be unwarranted at that time. Although the possibility of fully dismantling market-based rates in the U.S. is not the subject of these comments, FERC's remarks on this topic in June are relevant to the issue of whether market power monitoring and the assurance of just and reasonable rates should be accomplished through cost-based restrictions on all bids and market prices during all hours, and for all types of spot markets and bilateral contracts. In the event that FERC might have some of the same objections as expressed in its Western Order to the suggestions made here in favor of cost-based market power monitoring and mitigation, we will address some of those possible arguments here. It is reasonable to give FERC a little longer to try to sort out these complex issues in order to actually achieve just and reasonable rates, as long as more rapid progress is forthcoming in the near future. We hope that the relative quiescence exhibited recently in electricity markets continues while FERC wrestles with these issues, but it may not. Furthermore, FERC must always remember that the existence of relatively low electricity market prices does not mean that market power is not being exercised on a daily basis. Thus, the current relatively low market prices should not be used as an excuse to ease up on one's vigilance relative to market power issues. If certain generation owners can not make prices spike during times of peak demand, they might equally attempt to raise prices to a lesser extent in most other hours.

In its June 19 Order, the Commission also suggested that the complexity of establishing the cost of service and an appropriate rate of return for each generator would be time consuming and "that would not provide price certainty to the market." (Western Order, 24.) This is an odd statement since clearly the market never had "price" certainty. In the context of the approach to cost-based, full-time market power mitigation that we propose here, we argue that if market participants knew that FERC had set in place a strict market power mitigation system that was cost-based, there would be far less uncertainty about prices than under any other scheme, except to the extent that electricity market prices are determined by exogenous factors such as fuel prices. However, uncertainty regarding fuel prices is always a problem regardless of market structure.[5] What is very clear about a scheme like the one we have presented here is that the market would not suffer from uncertainty generated by a lack of clarity about how market power monitoring and mitigation would work. Moreover, the obvious remedy to any ambiguity about what competitive prices might be in each hour, where mitigation thresholds would be set, is the transparent separation of marginal costs into fixed and variable costs, between the capacity and energy market, respectively. Doing this would give all market participants a clear sense of what to expect in both the energy and capacity markets, helping to stabilize bids at competitive levels, and sending a much less ambiguous price signal to potential new market entrants than current energy markets do which yield very volatile prices precisely when new capacity is needed. Price signals in a well-run installed capacity market to new market entrants need not be inflated to induce market entry. They need to be accurate and transparent, as discussed further below. Of course, if FERC systematically creates annual installed capacity markets across the US as we suggest, then appropriate reserve margin requirements can also be set, and the installed capacity markets can be structured in a way to induce the needed amount of new market entry to meet the reserve requirements. If it turns out that market prices do need to be inflated above just and reasonable levels to induce new market entry even when reserve requirements are established, then it is clear that market mechanisms will not be defensible in the electricity industry at all.

The Commission also remarked in the Western Order that cost-of-service rates penalize those generators who make an effort to improve the efficiency of their operations and denies them appropriate scarcity rents. (Western Order, 24.) Being outside the scope of these comments,

[5] Indeed, uncertainty in fuel markets introduces risk premiums and greater volatility into deregulated markets than under cost-of-service regulation. This can also ultimately result in higher average market-based rates than cost-of-service rates.

we will set aside the question of whether this statement is true, and if true, whether it is something that FERC should be concerned about. In the context of cost-based monitoring and mitigation of market-based rates we would argue that it is always in the interest of the generation owner to improve the efficiency of its production. This is true even though the generator's "allowable" bid price would follow the variable cost of its production downward as efficiency improves. The reason is that for all generating units, except perhaps the ones with the highest variable cost and those that are dispatched the fewest number of hours each year, most of their annual revenue is generated when they are <u>not</u> the marginal unit (i.e., setting the market price). During those hours, generating units collect the infra-marginal revenues determined by the difference between the variable cost of the unit and the market price in any given hour. Increasing the efficiency of a unit increases the collection of these revenues, and the generation owner would therefore be given ample incentive to improve efficiency relative to the fixed cost recovery that the generator was allowed to collect in the annual installed capacity market when that payment was last set according to our proposal. This would be the same kind of "regulatory-lag" based incentive that currently exists to encourage efficiency improvements under traditional rate-regulation between rate cases. Therefore, setting market-monitoring thresholds based on a unit's cost-of-service would neither hurt price certainty, transparency, nor efficiency. The contrary would be true.

Separate capacity markets, when combined with energy markets with cost-based monitoring thresholds, would also be "pro-competitive" because by allowing for the proper allocation of costs and revenues between product markets, they provide less ambiguous price points for new market entry. Conversely, for existing market participants, relying on energy markets alone for full cost recovery increases the risk of under-collecting fixed capacity costs.

Since this risk is clear to market participants, they are likely to 'price-in' the risk premium associated with such uncertainty. Therefore, not only does a cost-based market monitoring model reduce the effects of market power, it would reduce the risk premium that inevitably accompanies deregulated power markets where guaranteed fixed cost recovery has been abandoned. We conclude that an appropriate market structure, particularly one where annual installed capacity and energy markets work side-by-side in a complementary manner, will facilitate market power monitoring and mitigation and will improve the likelihood of competitive behavior at rates which do not have excessively high ROEs built into them. Thus, such an approach would greatly increase the probability of achieving just and reasonable rates.

h. Installed capacity markets and a required reserve margin are also critical for maintaining system reliability.

One question that is bound to surface in response to our call for behavioral cost-based market monitoring and mitigation, is whether such a mechanism would not impede needed investment in generation resources. This was discussed briefly above. A traditional concern about market price mitigation is that with variable-cost screening of market bids, the inability of market participants to collect prices well in excess of short-run marginal cost might reduce investment due to the perceived inability to collect adequate total revenues. However, as we have discussed, this is not a reasonable concern provided that two conditions are met: A *required reserve margin* must be in place, and the energy market must be supplemented with an installed capacity market. We believe that that the key to ensuring adequate investment in generation resources continues to be the regulated reserve requirement which, in a deregulated market environment, we believe necessitates a separate market for generation capacity.

It can easily be argued that it is unimpeded market power in particular, and deregulated markets in general, rather than cost-based market power mitigation methods that are likely to hurt system reliability by resulting in shrinking reserve margins. Even in the absence of market power that may keep out new market entrants, the market is likely to deliver a tighter reserve margin if left to its own devices than if a regulated reserve margin of, perhaps, 18-20 percent were in place. What happened in California is a perfect example of this phenomenon. The reason is due to the significant risk of not collecting an adequate return on capital investment in generation resources in only an energy spot market, especially when bilateral contracts were discouraged. An "adequate" return in this context must, therefore, be adjusted for the risk involved when cost recovery is not assured. The result will likely be quite different, however, depending on whether or not a required reserve margin is in place. Without it, the result is likely to be an unacceptable reduction in reliability, because prices may not rise to cover the risk premium of adequate reserves.[6] In addition, there is a system cost (or social cost) associated with reducing system reliability that does not face the individual generators. Likewise, the relative lack of system resources tends to raise revenues for each unit due to making market power easier to exercise during times of peak demand, converting the relative lack of reliability into an economic incentive to keep reserves too low. With a required reserve margin and an installed capacity market in place, the result is likely to be adequate system reliability.

Apparently in recognition of these facts, FERC instituted required reserve margins in all three of the northeastern ISOs. Secondarily, FERC established capacity markets in these ISOs to allow generation owners a facility through which to recover their fixed costs of production.

[6] It is popular to think of reliability being yet another commodity in power markets that can be procured through competitive market structures, specifically capacity reserve markets. However, relative degrees of system reliability is not an exclusive good that can be traded. Individual units of capacity sold as reserves are not "units of reliability" Reliability is a system condition that affects all customers.

However, it has always been surprising that FERC failed to do the same in California, allowing that state to fall victim to natural market forces. As should have been expected, the market saw no reason to maintain reserves at a level that would have been determined necessary based on any reasonable loss-of-load analysis. Instead the market determined that reserves should be lower, reducing the price risk for marginal units, while creating relative scarcity that ultimately raised market prices and unit profits significantly over competitive prices that might have been realized from a more reasonable market structure with capacity requirements in place. It was only at this much higher price level which reflected scarcity rents that generators finally became interested anew in adding capacity, but only after reserve margins had fallen far below adequate levels. Unfortunately, FERC affirmed the market's "right" to extremely high risk premiums in the June 19 Western Order by implementing inflated price caps that were unjustly presented as providing proper mitigation of market power. In contrast, those high price caps simply validated and locked in the implications of a condition of seriously inadequate reserve capacity, because the price caps were based on the prior actual stage 1 deficiency prices. This continued a situation in which it was claimed that the full capital cost of new capacity could be recovered in only a year or two, a pricing scenario that would never be considered to be reasonable under cost-of-service regulation, where assumed depreciation rates have been 15-30 years, or more.[7] This outcome is even more perverse due to the fact that the capacity shortage in California was

[7] Consider an example of how the price caps introduced in the June 19 Order might validate non-competitive market results: If the highest variable dispatch cost in the worst stage #1 deficiency hour were $100 per MWH, which is quite possible, then the price cap for all non-deficiency hours in California would be $85 per MWH plus 10 percent for the California credit risk premium. This totals $93.50 per MWH. It could also be the case that the average variable dispatch cost in the non-deficiency hours would be only $50 per MWH, or lower. Over the course of 8760 hours per year, the extra revenues that could be derived from this market would be up to $43.50 per MWH for every hour of the year (except for a few hours during stage #1-#3 emergencies). This could happen if FERC's proposed price caps effectively set a price floor under all spot market prices. Thus, for every MW of capacity available 80 percent of the time, this amount of money would total about $43.50x0.80x8760, or about $305,000 per MW-year. This is about $305 per kW-year, or almost the full capital cost of a combustion turbine peaker.

directly linked to FERC's own failure to impose reserve requirements in the state. Needless to say, if sufficient new market entry had occurred in California in a timely fashion, the heat rates of the unit that set the market clearing price during the Stage 1 emergency might have been much lower.

Our conclusion is that the Commission should insist on adequate reserve margins in all regional wholesale electricity markets, provide for the proper pricing of capacity through installed capacity markets, and subsequently ensure that energy prices do not exceed competitive levels by monitoring energy markets on the basis of the incremental variable cost of generation from each unit. The Commission must reverse its apparent position of placing market autonomy first on its list of priorities, especially if it means accepting a lock-in of very high risk premiums and high market prices when supposedly attempting to mitigate the results of market power. We are mindful of the fact that under cost-based rates and rate regulation, risk premiums for generation were a much lesser concern, and the cost-of-capital for new generating units was much lower than may now prove to be the case in deregulated generation markets. FERC should remember that traditional cost-of-service regulation provides many advantages that deregulated markets may find difficult to deliver, just and reasonable rates being the chief one among them.

3. OUR COMMENTS ON THE SPECIFIC COMPONENTS OF THE TWO NOVEMBER 20TH ORDERS

a. We support inclusion of the proposed language on page 4 of the Tariffs Order in all market-based rate tariffs and authorizations, including those for RTOs and ISOs. Of course, the implementation process for market monitoring and mitigation must be defined in much greater detail than the Commission does in this Order.

We agree that the language: "As a condition of obtaining and retaining market-based rate authority, the seller is prohibited from engaging in anticompetitive behavior or the exercise of market power. The seller's market-based rate authority is subject to refunds or other remedies as may be appropriate to address any anticompetitive behavior or exercise of market power;" should be included in all past and future market-based tariffs and authorizations. But while inclusion of such language is a necessary condition for attempting to establish competitive markets, substantially more detail and a more comprehensive theory of market power is necessary in order to implement such conditions than is presented in the Tariffs Order, or in the AEP Market Power Order. We, therefore, support the idea that FERC should issue a Notice Of Proposed Rulemaking to solicit comments as to how this language should be implemented, both procedurally and conceptually, and on what market structures should be created to achieve this goal.

b. While the Commission has, in principle, identified some of the necessary steps toward identifying, preventing and correcting anti-competitive behavior, the language of the Tariffs Order implies a serious ambiguity regarding the Commission's determination to take those steps when needed.

In its Tariffs and Market Power Orders, the Commission has identified what we believe to be the three basic steps necessary to prevent anti-competitive behavior and the resulting wholesale power prices that can neither be regarded as just nor reasonable. These steps are the *detection* of market power and anti-competitive behavior, the proactive *mitigation* of such behavior by restricting market-based rate authority or by other appropriate means, and the *correction* of the effect of anti-competitive behavior through refunds of illicit revenues generated by such behavior. However, the language of the Tariffs Order, in particular, remains weak and somewhat ambiguous on FERC's commitment to comprehensive and aggressive mitigation and correction of market prices in the face of market abuses: "Should public utility market participants engage in prohibited behavior, their rates will be subject to **increased scrutiny** by the Commission, and **potential** refunds or such other remedies as may be appropriate." The

Commission goes on to specify that prohibited behavior "**could** result in further **conditions or restrictions** on [market participant's] market-based rate authority..." (Tariffs Order, 6 – emphasis added.) We believe that this type of language falls far short of describing the kind of aggressive and robust market power response that the Commission implies is necessary in the context of its obligation under the Federal Power Act to "**ensure** that sellers **<u>not charge</u>** unjust and unreasonable wholesale rates." (Tariffs Order, 5 – emphasis added.)

The vastly improved monitoring and detection methodologies for anti-competitive behavior that are required to accomplish the Commission's objective would, presumably, negate the need for any further *increased scrutiny* upon detection of market abuse by individual market participants. We would also anticipate that the illicit revenues derived from prohibited behavior would be subject to <u>full and unconditional</u> refunds, and not merely *potential* refunds. Finally, we would expect that a market participant that had abused its position in the market, and had been "caught in the act" by a more robust system of market monitoring, would, after appeal, pay a price by <u>losing outright</u> its market-based rate authority. The only reasonable exception would be if a substantial monetary penalty were imposed on the market participant in place of the revocation of market-based rate authority, provided that sufficient safeguards (i.e., restrictions on rate authority as opposed to revocation) were set in place to prevent the recurrence of abuse by the power supplier.

Indeed, it would seem reasonable that a monetary penalty should always accompany a need for market power mitigation, whether or not market-based rate authority is revoked or simply restricted in some fashion. The principle that should apply is that the offending party should never be indifferent financially between the two options of following the market rules, or facing Commission action upon the detection of market abuse. If a mere price correction is the final action taken when market abuse is detected, the deterrence of a financial penalty would be missing, and the market participant would receive the wrong message from the Commission, which would simply be to try to avoid detection next time a violation is planned. Unfortunately, the specific language of the Tariff Order implies that corrective action by FERC may waiver from this principle, leaving the prospect of appropriate penalties if price mitigation is required in serious doubt.

c. The Commission's definition of market power and anti-competitive behavior is flawed.

On page 4 of the Tariffs Order, the Commission states that exercises of market power "include behavior that raises the market price through physical or economic withholding of supplies." It continues by stating that "physical withholding would occur when a generator declares a forced outage when its unit is not, in fact, experiencing mechanical problems." This definition for physical withholding is basically correct, but no reference is then required to a market price in the next sentence. Either the unit is declared able to operate, or not. This situation is one of the few that is either "black or white."

The Commission's major conceptual error, both here and in most previous orders which deal with market power, lies in what they leave out of their list of ways in which market power can be exercised. We maintain that physical and economic <u>withholding</u> may be relatively easy to prevent, once the correct market rules are in place. However, what the Commission has omitted entirely from this list is the concept of <u>strategic bidding</u> as the main way in which market power can be, and has been, exercised. Certainly, strategic bidding played a major role in causing the high market prices that persisted in Western markets for about a year.

Strategic bidding is simply bidding above one's incremental operating costs in the energy, ancillary service, or capacity markets, thus attempting to drive the market clearing price as high as possible above a competitive level. Certainly, FERC needs no reminder that most generating units in the Western spot markets did this often over the last two years, and many generating units do this in the Northeastern ISO markets, as well. Perhaps the confusion that led to this key omission by FERC is that strategic bidding could end up with a unit being withheld, even if unintentionally, due to the high bid it submitted. This result could be called "economic withholding" using FERC's terminology, especially if a bid were submitted at such a high level that there would be little likelihood of the unit being dispatched. What FERC needs to realize, though, is that there is a broad continuum between the extreme case of planned economic withholding and routine strategic bidding, which might not cause a unit not to be dispatched, but which, due to the submission of a high price bid, might raise the market clearing price. In fact, strategic bidding is a rational strategy for generation owners to utilize in almost every hour for each of their generating units, in contrast to the more extreme case of economic withholding which would probably be done only occasionally.

It is particularly strange that FERC has omitted strategic bidding from its discussion of market power mechanisms on page 4 of the Tariffs Order. After all, in its June 19 Western Order FERC made it very clear that it expected units to bid incremental variable costs even when supplies were tight, and this was the basis of its price cap setting methodology. This FERC action was, then, implicit recognition of the existence of strategic bidding. Thus, it is especially surprising that FERC does not explicitly recognize on page 4 that generating units that bid above their incremental variable operating cost is the prime way in which market power is exercised.

d. The Commission's definition of market power erroneously implies the existence of a legitimate and "autonomous" competitive market price that can somehow exist during periods of anti-competitive market behavior. This error seems to contribute, in part, to FERC ignoring the more common exercise of market power through strategic bidding.

When defining two of the generally recognized means of exercising market power, economic and physical withholding, the Commission seems to posit a market price that both results from anti-competitive behavior, but which is still as being distinguishable from a legitimate, competitive market price. We are concerned that this confusion could lead to ineffective market monitoring methodologies. The Tariff Order states: "Economic withholding occurs when a supplier offers output to the market at a price that is above both its full incremental cost **and the market price** (and thus, the output is not sold)." (Tariff Order, 6 – emphasis added.) The problem is that FERC is not clear whether the term "market price" here refers to a competitive market price or one inflated by the exercise of market power. If FERC believes this could be a competitive market price, they are likely to be mistaken.

What FERC is ignoring is the fact that by attempting to economically withhold capacity by raising a bid, the offending party is likely to indirectly raise the market price above a competitive level. This is the new higher price that the bidder will recover on its other units that are being dispatched. That is the whole point as to why a party might be motivated to attempt economic withholding. The way in which economic withholding works is to force the market price up by making the supply curve steeper.

Therein lies the difference between the two main forms of market abuse, capacity withholding and strategic bidding/economic withholding. Capacity withholding serves to *shift* the supply curve to a higher price range by completely removing a resource from where it would have been in a competitive supply curve. On the other hand, strategic bidding is not aimed at necessarily withholding capacity altogether, but it is aimed at raising the market clearing price in the neighborhood of where that specific capacity normally would fall in a competitively-based supply curve. Each time either economic withholding or strategic bidding occurs, the resource moves up the supply curve, also making the whole curve steeper, thus usually raising the market clearing price, whether that resource is actually dispatched, or not. Thus, when economic withholding occurs, the market price even after being raised due to market power, would still end up somewhat lower than the resource bid price, causing the resource not to be dispatched, as in FERC's definition.

Therefore, the Commission should clarify its definition of economic withholding by recognizing that when market power is being exercised, there will not likely be a concurrent competitive market price that is not tainted by this exercise of market abuse. One reason why this clarification is necessary is so the Commission can, again, be clear that there is no bright line between strategic bidding and economic withholding, since in the exercise of strategic bidding the offending party can never be quite sure if raising the bid on a resource above its incremental variable operating costs will cause it not to be dispatched. Thus, even if the output of a resource is sold (dispatched), and economic withholding does not occur, this fact does not imply that the market price is competitive and not in need of mitigation.

e. The Commission's apparent notion of an autonomous market price during periods of anti-competitive behavior in the Tariffs Order mirrors similar concepts contained in market rules that they have approved for the Northeastern ISOs, and suggests a preference for market "autonomy" over market discipline.

Other types of self-referential tests for market power abuse also plague the market monitoring rules that FERC has previously approved for the Northeastern independent system operators. An example of this is when a market monitoring rule looks to historic bidding behavior as a baseline, and compares this to current bidding behavior to determine whether market abuse currently exists. This is obviously troublesome because the monitoring rule may look to an historic baseline period that is already affected by non-competitive bids, thus serving to allow even more market power in the current time-period than occurred in the baseline period. Market simulations have shown that the exercise of market power by generation owners is not likely to be an occasional affair, but rather a consistent and ever-present element. Therefore, establishing baselines from historical bidding behavior is likely to be useless when monitoring future bidding behavior. The alternative, of course, is to simply compare current bids to incremental variable costs, and not in a self-referential way to past bidding behavior in order to provide a meaningful baseline.

FERC's past approach to monitoring for market power seems to reflect its general resistance to ever abrogate the autonomy of the market and to question the results it delivers, because to do so would somehow negate the principles of deregulation in which it believes. This sentiment may stem from the fact that the only reasonable remedy to market prices that have been manipulated through the exercise of market power is the imposition of cost-based bids, and that, to some, is tantamount to a restoration of cost-of-service regulation, which FERC is resisting even when it is necessary. That is a sensitive situation that ISOs and other market operators want to avoid facing because it raises the ever-looming question of whether there has been any true benefit, relative to traditional rate regulation, that the deregulated wholesale markets have delivered. In the context of these Orders, the question is whether market autonomy should have precedence over the quest for lower prices and rates that are just and reasonable.

Fortunately, the Commission has demonstrated with its new Market Power Order that it has no objection to imposing cost-based bids on offending power suppliers in some contexts (but not all). Therefore, we would suggest that the Commission clarify its position on this matter and denounce the self-referential tests for market power that refer to "the market price" as conceptually autonomous from the effects of market power. Furthermore, FERC should acknowledge that the marginal costs of electric generation provide the only true test of whether generation owners have placed non-competitive bids. FERC should, therefore, revise all its market power monitoring rules for the three Northeastern ISOs to make them cost-based.

f. The Commission should recognize that its Supply Margin Assessment screen is just as arbitrary as the hub-and-spoke methodology for detecting a "safe" level of market share, and that it cannot "ensure" protection against market power irrespective of its attempt to incorporate transmission constraints. Therefore, this interim measure should not be a model for either an interim or a permanent market power test.

The previous benchmark for establishing whether a market participant had market power was a market share of 20 percent in each market delineated by the hub-and-spoke methodology. The SMA test attempts to improve on this approach in two ways. First, it considers transmission constraints as a potential factor. Secondly, "in determining the size that triggers generation market power concerns," the SMA sets the threshold where the "applicant's capacity must be used to meet the market's peak demand" within any given control area. (Market Power Order, 7.) The commission calls this test a determination of whether the seller is "pivotal" in the market: "When an applicant is pivotal, it is in a position to demand a high price above competitive levels and be assured of selling at least some of its capacity." (Market Power Order, 7.) The SMA test has been presented as an interim improvement on the previous methodology "to **ensure** that customers are protected against market power in generation." (Market Power Order, 7 – emphasis added.)

In contrast, we believe that there can be absolutely no assurance that this test will eliminate most market power, because it certainly cannot ensure competitive bids. Instead, this test is intended to screen for only those suppliers who hold the most insidious form of market power, which is when the market is an *absolute price taker* in relation to a single supplier. It is true that during a period of high demand, when the supply held by a single market supplier is greater than the supply margin, some of the output of that supplier must be bought if the generation resources are not committed to any specific load. Therefore, the purchase will take place at any cost in the absence of a price cap in the market. However, the absence of absolute pricing power during periods of high demand does not mean that market power does not exist during other periods, even when monopoly pricing power is not feasible.

To equate market power with the capability for absolute pricing power contradicts the Commission's own definitions in the Market Power Order as to how market power is exercised. Economic withholding that results in rising market clearing prices is an example of the exercise of market power without absolute pricing power. The same is true for capacity withholding and for the more common mode—strategic bidding. In other words, the exercise of market power has been defined and described by the Commission in the Tariff Order in a context where the offending party does not have to be in a "pivotal" market position. Given this serious inconsistency between the two Orders, how can the Commission defend its use of the SMA screen as a tool "applied to ensure that customers are protected against market power"? Again, FERC needs to be clear that the exercise of market power is a behavioral problem that occurs within the context of a particular market structure, but no structural screen can possibly detect all possible opportunities to exercise these types of undesirable behaviors.

g. The Commission should correct and augment the definition of anti-competitive behavior as it appears in the Tariff Order. An improved behavioral definition, and all relevant tools for market monitoring based on that definition, are far more important than the new SMA market power test which is highly flawed because it is structural. Otherwise, the proper conceptual basis for detecting all abuses of market power will be missing, as will be the ability to mitigate and correct such abuses.

There are two components to detecting the abuse of market power. One step is to apply a test that determines with a high level of confidence whether market participants actually possess the potential to exercise market power. The second step is to apply a test that shows whether that market power has actually been exercised on an ongoing basis. The Commission's Market Power Order presents an interim structural market power test, which is intended to determine whether a single market participant has the potential to exercise market power. In contrast, it is the Tariff Order that attempts to define what *behavior* actually constitutes market power. However, both Orders fail to do their jobs adequately, as discussed previously.

We believe that for FERC to develop a strong and unequivocal definition of anti-competitive behavior is far more important a task in the ongoing effort to improve the competitiveness of wholesale power markets than the institution of a subjective, and largely arbitrary, new structural threshold for determining the existence of market power. In summary, the reason why we believe this is true is very simple: A strong and effective behavioral test will always detect market power abuse when it occurs, regardless of the market share held by the offending party, while a structural market power test targets market participants based on their market share irrespective of whether or not market power was, or even could be, exercised. Even more fundamentally, structural tests are never able to detect all situations in which there is the potential for the exercise of market power. Structural tests alone can never be adequate because they can not be comprehensive.

The superior quality of a behavioral test over a structural one is apparent because it targets the offensive behavior directly, rather than merely targeting market share or other structural features of a market which only determine in part to what extent market power can be exercised. If this is true, then why would the Commission maintain a preference for structural tests? Again, we suspect that the problem lies in the Commission's reticence to curtail the autonomy of the operations of the energy and/or capacity markets in setting "the market price." A strict behavioral test must continuously monitor the market for anti-competitive bids, preferably applying marginal cost-based tests, as discussed above. A structural screen only leads to intervention if a single participant holds a disproportionate share of available supply. Otherwise, it assumes that the market will produce just and reasonable prices. Therefore, the behavioral test will tend to be perceived as a much greater constraint on the free movement of prices within the range that the market might produce. Again, FERC may see this as antithetical to the principle of deregulated power markets. However, we believe that the continuous monitoring of bids and market clearing prices, with reference to the marginal cost curves of the resources making up the supply in that particular type of market, is the only certain path to adequate protection against market abuses. In particular, energy market bids must be monitored for correspondence with marginal operating costs, and capacity markets must be examined for correspondence with marginal fixed costs based on a regulated range of return on equity.

h. If the Commission intends to continue to use structural screens at all in evaluating wholesale power markets, it should recognize them to be merely crude safeguards or "gate keepers," and not sufficient protection against market power, which can only be accomplished through behavioral screens. However, to avoid confusion, it would be better not to use structural screens at all in order to avoid "false negative" diagnoses for the existence of market power.

In the Market Power Order, the Commission has not even attempted to show that a "pivotal" market share is the appropriate threshold for all market power abuses. Moreover, any such structural screen is, by definition, at odds with behavioral definitions of how market power is exercised, since economic and capacity withholding, and strategic bidding, are not dependent on a single generation owner being in a pivotal market position, as discussed above. Therefore, the Commission cannot defend the presentation in these two concurrent Orders of fundamentally contradictory definitions of what constitutes anti-competitive behavior. The only remedy is to recognize that structural screens are only crude tools that might reduce the probability of the worst offenses, and that such screens must be followed quickly by a more refined analysis of market behavior during all hours *irrespective of load conditions and market ownership shares.*

i. The Commission should require all electric generating units selling into U.S. wholesale markets to post their projected 24-hour incremental costs for energy offered for spot market or other market sales, to enable full-time monitoring of all bids and bilateral contracts for competitive behavior. Such monitoring should not be limited to generation owners that fail the SMA screen. The annual fixed costs of each generating unit based on a generic ROE value set by FERC should also be reported for use in monitoring capacity markets and longer-term bilateral contracts.

Since the SMA screen cannot prevent abuses of market power, it is obvious that behavioral screens must be used to replace (or supplement) structural screens like the SMA for all generation owners in the U.S., irrespective of their passing the SMA screen. The use of behavioral screens that are based on the marginal cost structures of market resources would require that all resources post their incremental marginal cost data—both the variable and fixed costs for use by all agencies responsible for market monitoring and mitigation.

j. The Commission's actions in issuing its two key November 20, 2001 Orders are to be praised, even if they are long overdue.

It is a significant moment in the development of deregulated wholesale power markets when the Commission moves to recognize and act more broadly on its obligation to ensure just and reasonable rates under provisions of Section 206 of the Federal Power Act. It would be extremely unfortunate if this were also the occasion of widespread cynicism and disbelief among wholesale market participants who seriously mistook the Commissions actions as an underhanded move to simply further the agenda of RTO formation. It is particularly important for the Commission to affirm its wholehearted commitment, above all secondary objectives, to quell market abuse because the assurance of just and reasonable rates, along with reliable service, should be its first priority as the federal administrator of the wholesale power markets. Therefore, the Commission should make a further effort to prevent these Orders from being seen as sacrificing the principle, or trivializing the objective, of just and reasonable rates for the sake of furthering the formation of RTOs, which some might believe would not ultimately be subject to equally rigorous standards to prevent the abuse of market power. After all, the Tariffs Order, which is the more sweeping and fundamental of the two Orders, applies equally to ISOs, RTOs, and all other market-based rate tariffs.

Respectfully Submitted,

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DATED: January 4, 2002

CERTIFICATE OF SERVICE

I hereby certify that I have this day filed the foregoing documents at the Federal Energy Regulatory Commission by electronic filing and served a copy upon each person designated on the official service list compiled by the Secretary in this proceeding.

I further certify that the paper copies mailed to the parties on the official service list contain the same information as contained in the electronic media filing, that I know the contents of the electronic media and the paper copies and that the contents as stated in the copies and on the electronic media are true to the best of my knowledge and belief.

Dated at Providence, RI, this 4th day of January, 2002.

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